ORIGINAL

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March 1, 2016

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

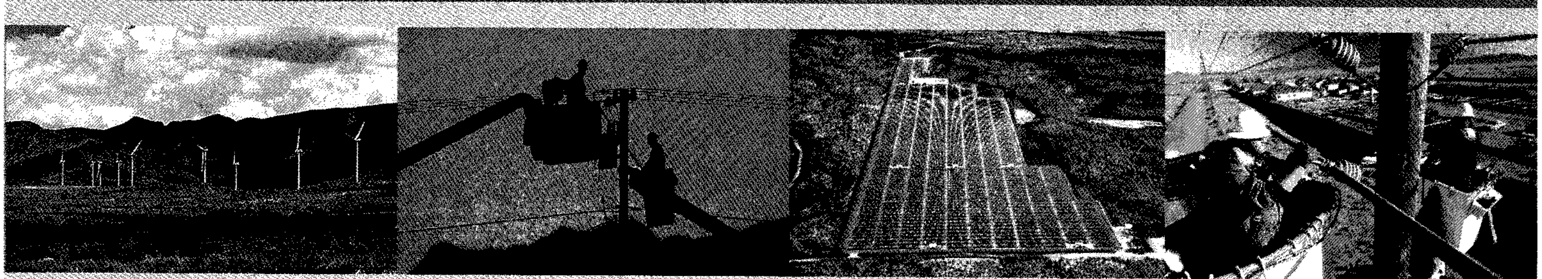
Re: Notice of Filing –UNS Electric, Inc.'s 2016 Preliminary Integrated Resource Plan, Docket No. E-00000V-15-0094, Decision No. 75269

Pursuant to A.A.C R14-2-703 and Decision No. 75269 (September 16, 2015), Tucson Electric Power Company hereby files its 2016 Preliminary Integrated Resource Plan.

If you have any questions regarding this filing, please contact Mike Sheehan at (520) 884-3656.

Sincerely,

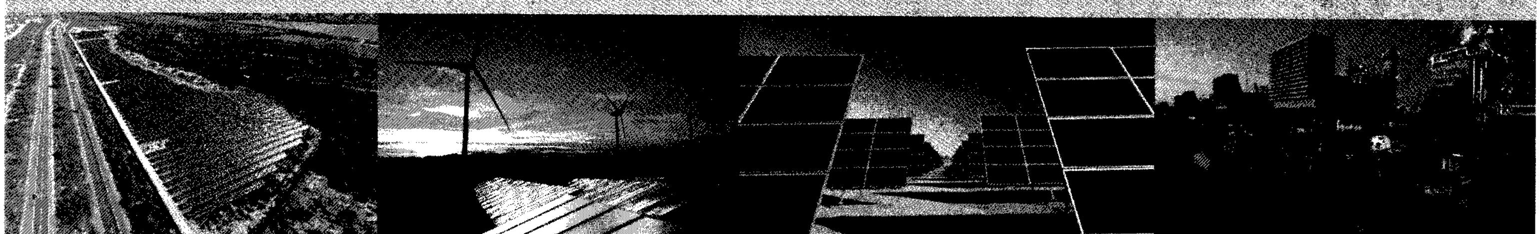
Melissa Morales
Regulatory Services



UNS Electric, Inc.

2016 Preliminary Integrated Resource Plan

March 1, 2016



Foreword

New environmental regulations, emerging technologies and changing energy needs have reinforced the importance of long-term resource planning to UNS Electric and other electric utilities. Whatever the future may bring, our 2016 preliminary Integrated Resource Plan ("IRP") outlines our strategy for ensuring that UNS Electric's safe, reliable electric service remains a constant in our complex, evolving industry.

We will continue to expand our use of cost-effective renewable energy resources and energy efficiency programs for customers. In 2016, we'll add 35-megawatt ("MW") of solar capacity at UNS Electric, increasing the total renewable energy portfolio to 62 MW. We also will expand our energy efficiency resources through several new programs available this year. In the future, demand response partnerships with customers could help UNS Electric manage peak load demands while reducing the need for new infrastructure.

As requested by the Commission, this preliminary IRP report addresses the status of emerging resource options like energy storage technologies and small nuclear reactors. Although not all options are viable at this time, we will continue to assess their potential value as part of our resource planning process.

Since filing its 2014 IRP, UNS Electric has strengthened its generating portfolio and reduced its reliance on the wholesale energy market through the purchase of a 138 MW share of the efficient natural gas-fired Gila River Power Station in Gila Bend. The fast-ramping capability of this efficient resource makes it a critical compoment of our long-term strategy to expand use of renewable resources.

UNS Electric continues to evaluate the potential impact of the Clean Power Plan ("CPP") issued last year by the U.S. Environmental Protection Agency. The resource plan outlined in this document should put us in a strong position to comply with the new rules, which would require a 32-percent reduction in carbon dioxide (CO_2) emissions from Arizona power plants. UNS Electric does not own or operate coal-fired generators, so the CPP would not affect us as significantly as other electric providers. But the status of the CPP is in question after the U.S. Supreme Court issued a stay suspending enforcement of the rules pending further ligitation.

UNS Electric's continued evaluation of new resources is an important part of our efforts to provide safe, reliable and cost-effective service to customers. We intend to provide more robust resource planning information for UNS Electric's final IRP in 2017.

David G. Hutchens
President and CEO

Acknowledgements

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Chapter 1

Executive Summary

Introduction

UNS Electric's (UNSE's or the Company's) 2016 preliminary Integrated Resource Plan ("IRP") introduces and discusses the issues that UNSE plans to analyze in detail for the final 2017 Integrated Resource Plan. The purpose of this report is to provide regulators, customers and other interested stakeholders an opportunity to understand the current planning environment and provide feedback on the Company's future resource plans prior to the 2017 Final IRP submittal on April 1, 2017.

In addition to providing a snapshot of UNSE's current loads and resources, this report provides an overview of current resource cost assumptions, forward market conditions as well as a discussion on some new emerging technologies. This report also highlights a number of changes in the Company's resource plans since the 2014 IRP and discusses some of the new infrastructure requirements and policy decisions that must be addressed over the next few years.

2016 Preliminary Integrated Resource Plan Requirements

In accordance with Decision No. 75269 (Docket No. E-00000V-15-0094), the Commission ordered the Arizona load serving entities to file a preliminary IRP on March 1, 2016 with the final IRP report due April 1, 2017. This order stipulated that the preliminary IRP includes the following topics;

- Load Forecast
- Load and Resource Table (including technology discussion)
- Sources of Assumptions and Technologies Evaluated
- Status update on Company's plan to participate in the Energy Imbalance Market ("EIM")
- Scenarios Requested in 2014 IRP Decision (No. 75068)
    - Energy Storage
    - Small Nuclear Reactors
    - Expanded Renewables (including distributed resources): biogas, solar, wind, geothermal, etc.
    - Expanded Energy Efficiency/demand response/integrate demand side management (which shall include the effect of micro-grids and combined heat and power)
- Proposed Sensitivities
- Future Action Plan

Updates on UNSE's Resource Planning Strategy since the 2014 IRP

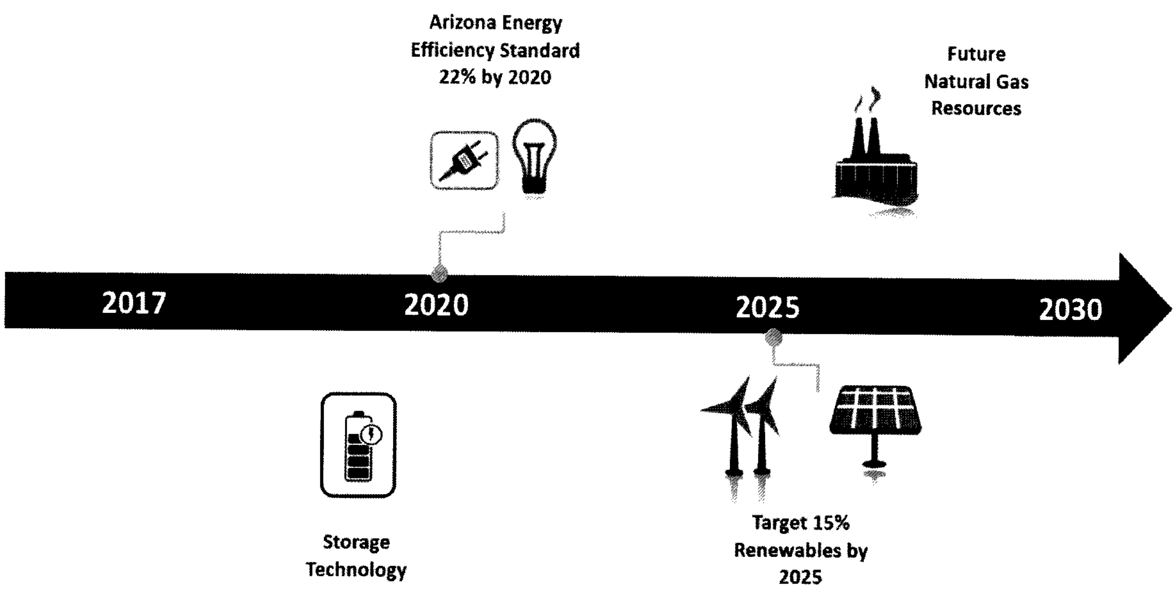
Gila River Unit 3

In December 2014, Tucson Electric Power ("TEP") and UNSE acquired Unit 3 at the Gila River Generating Station for $219 million. Gila River Unit 3 is a 550 megawatt natural gas combined-cycle power plant located in Gila Bend, Arizona. Today, low natural gas prices make Gila River Unit 3 one of lowest cost generation assets for both TEP and UNSE. Gila River's fast ramping capabilities, along with its real-time integration into TEP's balancing authority, provide both TEP and UNSE with an ideal resource to support the integration of future renewables.

UNSE's Long-Term Resource Diversification Strategy

The addition of Gila River 3 boosted UNSE's generating capabilities to cover a significant amount of its baseload and intermediate capacity requirements. UNSE is well-positioned to shape its resource portfolio mix more aptly to the final outcome of the State Implementation Plans ("SIP") and the Clean Power Plan ("CPP"). UNSE is committed to follow through on its long-term portfolio diversification strategy to take advantage of other near-term opportunities to comply with the CPP, the Arizona Energy Efficiency Standard and the Arizona Renewable Energy Standard. UNSE will study the potential of storage technologies and natural gas generating resources that will be utilized to meet growing demand and to help mitigate the challenges that are presented with the intermittency and variability of renewable resources. UNSE plans to file these details on its diversification strategy in the 2017 Final IRP.

Figure 1- UNSE's Long Term Resource Diversification Strategy



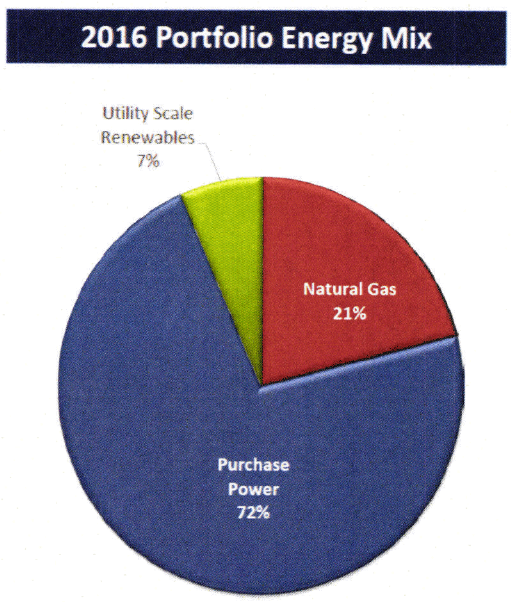
Transmission Resources

UNSE's transmission resources include approximately 334 miles of transmission lines owned by UNSE, long-term transmission rights (Point-to-Point and Network service) purchased from Western Area Power Administration ("WAPA"), TEP, and Point-to-Point transmission purchased from other transmission providers on an ad hoc basis. Given UNSE's dependence on third-party transmission providers UNSE works closely with WAPA's transmission planning group to ensure adequate long-term transmission capacity is available to serve the Mohave service territories. WAPA recently conducted an updated System Impact Study ("SIS") for UNSE to address current and future load growth forecasts. Based on WAPA's available transmission capacity, the load serving capability for Mohave County is sufficiently above the load projections within the study period of the 2017 Final IRP. In Santa Cruz County, UNSE completed the Vail to Valencia 115 kV to 138 kV transmission upgrade in December 2014.

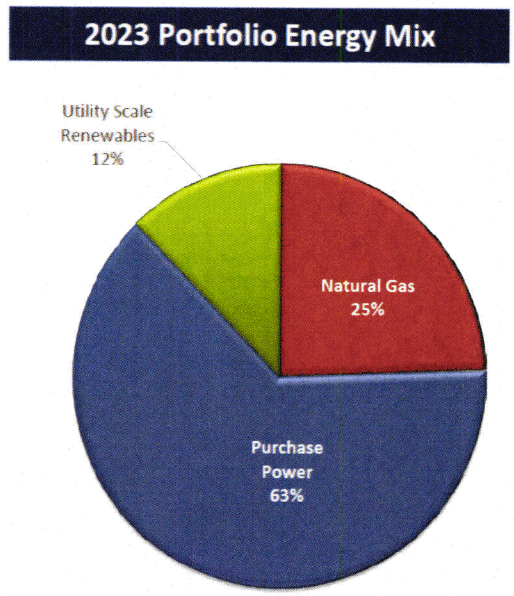
Achieving 15% Renewables by 2025

UNSE plans to continue development of low cost renewable projects that provide long-term value to UNSE's retail customers in Mohave and Santa Cruz counties. UNSE continues to be committed to meet a target of 15% of retail energy needs with renewable energy resources by 2025. Figure 2 below, illustrates UNSE's commitment to expand its renewable resource portfolio. By 2023, UNSE expects to exceed the Renewable Energy Standard.

Figure 2 – UNSE Portfolio Energy Mix



Energy Efficiency reflects 8.3% of retail sales. Utility Scale Renewables reflect 8.6% of retail sales and Distributed Generation reflects 2.6% of retail sales.



Energy Efficiency reflects 16.7% of retail sales. Utility Scale Renewables reflect 14.0% of retail sales and Distributed Generation reflects 3.9% of retail sales.

Supporting Future Renewable Integration

As part of this IRP planning cycle, UNSE is currently evaluating a number of technologies to support UNSE's ramp up in renewable resources. Reciprocating engines and battery storage are two technologies being considered to support renewable integration.

Natural Gas Reciprocating Engines

Reciprocating engines, while not new technology, are emerging as potential alternatives in large-scale electric generation. Advances in engine efficiency and the need for fast-response generation make reciprocating engines a viable option to stabilize variable and intermittent electric demand and renewable resources. As part of the Company's commitment to target higher levels of renewables, UNSE is evaluating the cost and operational characteristics of reciprocating engines as an alternative to both frame and aeroderivative natural gas combustion turbines. As part of the 2017 Final IRP, UNSE plans to provide an in-depth analysis on costs, uses and potential benefits of this technology to support renewable integration.

Battery Storage

In the spring of 2015, TEP issued a request for proposals ("RFP") for the design and construction of utility-scale energy storage systems. Currently TEP is working with two vendors to finalize the plans for two 10 MW lithium ion battery storage projects. While 20 MW represents only 1% of TEP's peak retail load, these projects are large enough to have a measurable impact on supporting grid operations. Assuming the performance from these first two installations is favorable, TEP would then consider future energy storage projects as a viable option for regulation and frequency response to support the expanded use of renewable resources. Both of these projects await Commission approval through TEP's 2016 Renewable Energy Standard and Tariff Implementation Plan (A.A.C. R14-2-1813) (Docket E-01933A-15-0239). TEP anticipates that the pending storage projects will be in service during the early months of 2017. Chapter 6 provides more detail on these TEP specific projects along with an in-depth analysis by Lazard[1] on storage technologies that highlight storage costs, uses and technology combinations. UNSE will monitor the TEP battery storage project and will analyze its applicability within the UNSE service territory.

Since 2011 UNSE has helped customers save more than 155,000 megawatt-hours, enough energy to power nearly 14,500 homes for a year. These savings help UNSE work toward the goals in Arizona's EE Standard, which calls on utilities to achieve cumulative energy savings of 22 percent by 2020.

[1] Lazard is a preeminent financial advisory and asset management firm. More information can be found at https://www.lazard.com

Compliance with the Clean Power Plan

On October 23, 2015, the EPA published a final rule regulating, for the first time, "CO_2" emissions from existing power plants. In general, this final rule, referred to as the "Clean Power Plan" ("CPP"), aims to reduce CO_2 emissions from U.S. power plants by 32% from 2005 levels by 2030. More specifically, the rule establishes emission guidelines based on EPA's determination of the "best system of emission reductions", which States and tribes (hereto referred to as "States") must use to set standards applicable to the affected plants in their jurisdictions.

Arizona is one of 27 states challenging the EPA's rule making authority and Arizona has filed suit against the EPA. On February 9, 2016, the United States Supreme Court issued a stay of the CPP[2] meaning that the rule has no legal effect pending the resolution of the state and industry challenge to the rule. That challenge is currently before the U.S. Court of Appeals for the D.C. Circuit, which will hear oral arguments on June 2, 2016. In all likelihood, this means a D.C. Circuit decision will not be issued until early fall, at the earliest. Given all that's at stake, either *en banc* review on the D.C. Circuit or a petition for certiorari likely will follow.

The CPP establishes emission goals for two subcategories of power plants in the form of an emission rate (lbs/MWh) that declines over the period from 2022 to 2030. Those subcategories are:

- Fossil fired steam electric generating units ("Steam EGUs") - includes coal plants and oil and natural gas-fired steam boilers
- Natural gas-fired combined-cycle plants ("NGCC")

Then using these rates ("Subcategory Rates") and the proportional generation from steam EGUs and NGCC plants in each state, the CPP derives state specific goals ("State Rates"). The CPP also converts these emission rate goals to total mass (i.e. short tons) goals for each state. Each state is required to develop a State Plan that will regulate the affected plants in their jurisdiction. UNSE will be subject to the Arizona State Plan. Table 1 below shows the applicable rate goals.

Table 1 - CPP Rate Goals

CO_2 Rate (lbs/MWh)	2022-2024	2025-2027	2028-2029	2030+
Subcategorized Rate - Steam EGUs	1,671	1,500	1,308	1,305
Subcategorized Rate - NGCC	877	817	784	771
State Rate - Arizona	1,263	1,149	1,074	1,031

There are three primary forms of the State Plan available to states (with sub-options):

Rate Plants are required to meet an emission rate standard (lbs/MWh) equal to the plant's emissions divided by the sum of its generation and the generation from qualifying renewable energy projects and/or verified energy efficiency savings. A rate plan could be administered through the use of emission rate credits ("ERCs"), where sources with emissions above the standard generate negative ERCs when they operate, and sources

[2] http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf

with emissions below the standard (or no emissions) generate positive ERCs. At the end of a compliance period, each affected plant must have at least a "zero" balance of ERCs.

Under the rate approach, states have the option of measuring compliance against the *State Rate* or the *Subcategory Rates.*

Mass	Plants are allocated (or otherwise acquire) allowances, the total of which equals the state's mass goal, and each plant must surrender an allowance for each ton of CO_2 emitted during a compliance period. Owners of plants that do not have sufficient allowances can reduce emissions by curtailing production, re-dispatching to a lower emission resource, or retiring the plant and re-distributing allowances to their remaining plants.
State Measures	Instead of regulating power plants directly, a state could implement policies that will have the effect of reducing emissions in their state such as building codes, renewable energy mandates or energy efficiency standards. Compliance is measured based on emissions from the affected plants.

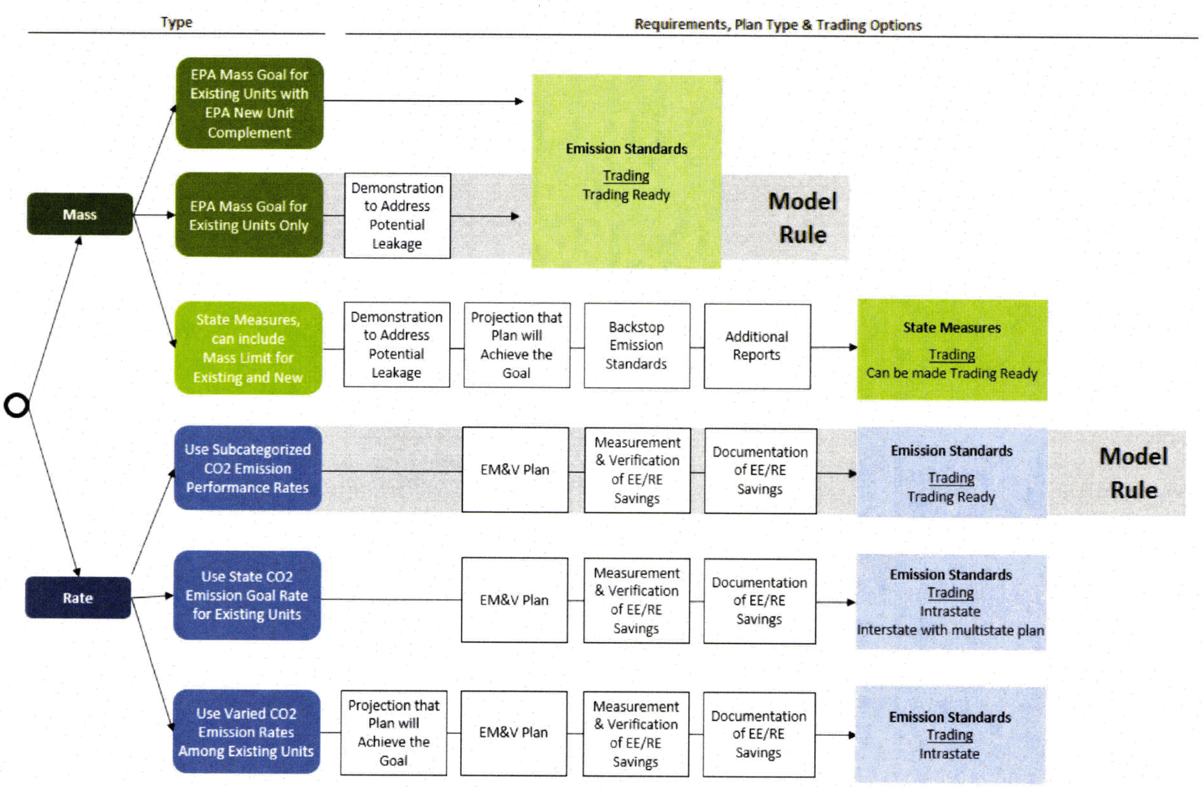
Arizona

The State of Arizona has been proactive in planning for CPP compliance. Following submittal of comments to EPA's proposed rule, and prior to the EPA issuing the final rule, the Arizona Department of Environmental Quality ("ADEQ") continued working with stakeholders, and through a series of meetings accumulated a list of Potential Compliance Strategies[3]. After the final rule was issued, ADEQ continued to meet with stakeholders and one of its initial steps was to develop 10 Principals of an Arizona Response to the Clean Power Plan[4]. During this phase of CPP planning ADEQ formed a Technical Working Group to assist in evaluating technical aspects of the plan.

The State of Arizona has previously stated it is committed to developing a State Plan. Due to the complexities inherent in developing a State Plan, the State of Arizona also indicated that it would file an interim plan prior to September 6, 2016, and request a two-year extension for filing the final State Plan. However, this timing will be delayed in light of the U.S. Supreme Court stay of the rule.

In preparing for the initial plan submittal, ADEQ organized the options for the form of a State Plan into subsets of Rate or Mass, and has expressed an interest in focusing on the most likely options.

Chart 1 – ADEQ Regulatory Framework Options[5]

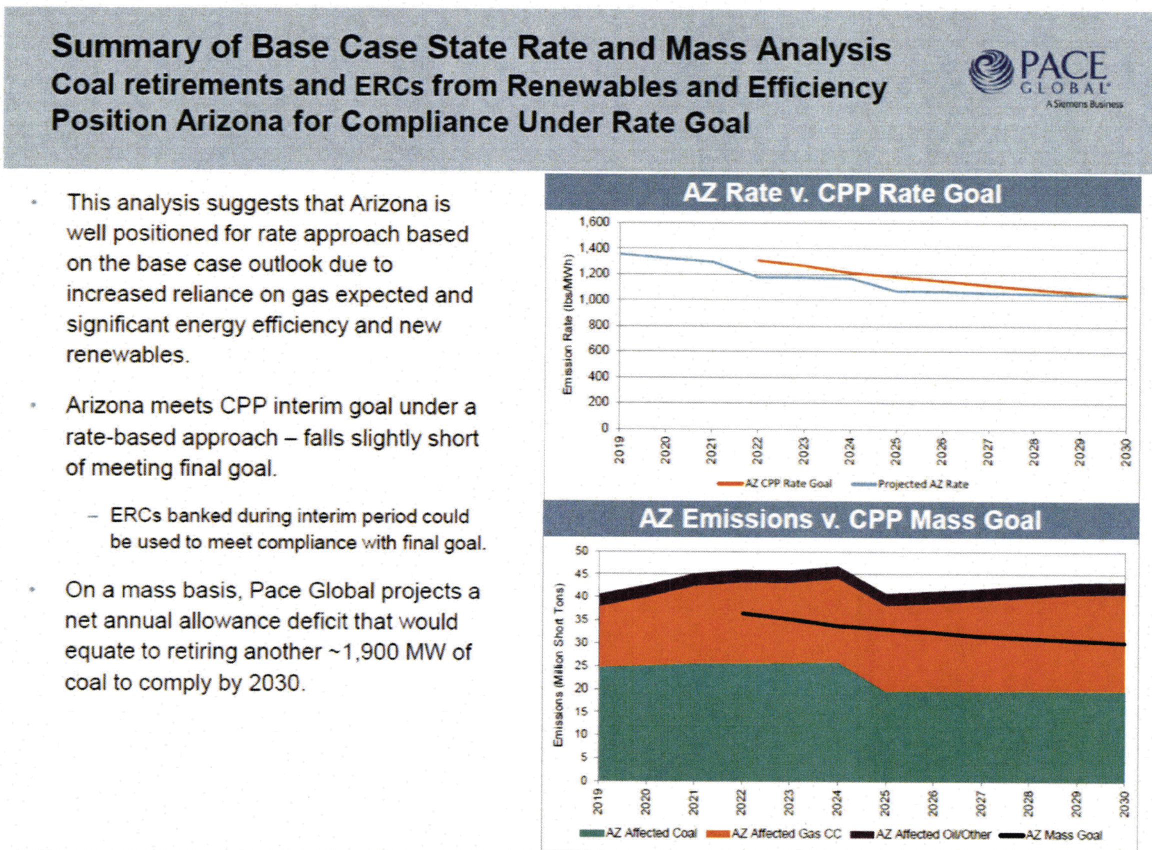


[3] http://www.azdeq.gov/environ/air/phasetwo.html
[4] http://www.azdeq.gov/environ/air/phasethree.html
[5] Ibid, ADEQ "EPA's Final Clean Power Plan: Overview, Steve Burr, AQD, SIP Section, September 1, 2015

PACE Global Arizona CPP Analysis

To help evaluate the relative benefits of Rate versus Mass for Arizona, the Arizona utilities hired PACE Global ("PACE") to conduct a modeling assessment of the relative compliance position compared to the State Rate and Mass goals based on a base case outlook. The results[6] of that assessment indicate that Arizona would likely fall short of the allowances needed to cover emissions using a mass approach. However, Arizona was able to meet the rate goals for the vast majority of the compliance period studied. A rate based plan, in general, better accommodates the need to meet future load growth with existing plants, and the subcategory rate approach is generally considered better for resource portfolios with a high percentage of coal-fired generation.

Figure 3 – PACE Global Arizona CPP Analysis



While the final legal status of the CPP has yet to be determined, it is worth noting that UNSE's ongoing resource diversification plan is consistent with the goals of the CPP with a generation portfolio source primarily from natural gas, renewable energy, and energy efficiency.

[6] More information can be found at http://www.azdeq.gov/environ/air/phasethree.html#technical

Energy Efficiency in the Clean Power Plan

In the final rule, EPA identifies a variety of energy efficiency measures, programs, and policies that can count toward compliance of the CPP. These include utility and nonutility energy efficiency programs, building energy codes, combined heat and power, energy savings performance contracting, state appliance and equipment standards, behavioral and industrial programs, and energy efficiency in water and wastewater facilities, among others.

Energy Efficiency under Mass Based Compliance Programs

Under a mass based approach, energy efficiency inherently counts toward compliance and states can use an unlimited amount to help achieve their state goals. Energy efficiency inherently counts toward compliance under a mass based approach since it displaces actual fossil generation and the associated emissions under a mass cap, freeing up allowances for sources use towards their remaining effected EGUs or to trade. There is no limit on the use of energy efficiency programs and projects, and energy efficiency activities do not need to be approved as part of a state plan, therefore, Evaluation, Measurement and Verification (EM&V) is generally not required for mass based approaches under the Clean Power Plan.

Energy Efficiency under Rate Based Compliance Programs

Under rate based plans, quantified and verified megawatt hours (MWh) from eligible energy efficiency measures in a rate based state can be used to generate ERCs and adjust the CO_2 emission rate of an affected EGU, regardless of where the emission reductions occur. Energy efficiency under ate rate based plan must undergo EM&V. The final CPP gives states with rate based plans the ability to design their programs so that they are ready for interstate trading of ERCs, including those issued for energy efficiency, without the need for formal arrangements between individual states. These state plans recognize ERCs issued by any state that also uses a specified EPA approved or EPA administered tracking system.

Energy Efficiency and the Clean Energy Incentive Program ("CEIP")

EPA has also proposed an early credit option for states called the CEIP. The CEIP awards early credit for low-income energy efficiency programs and certain renewable energy projects implemented in 2020 and 2021. The program offers a two-to-one match for state energy efficiency savings in order to incent these efforts prior to the start of the compliance period. The final rule also requires states to incorporate the needs of low-income and underserved communities within their compliance plans, and fully engage these communities along with other stakeholders during the planning process.

Transmission and Distribution Efficiency Measures

EPA's final rule also allows transmission and distribution ("T&D") measures that improve the efficiency of the T&D system to count towards emission reductions and compliance options. This includes T&D measures that reduce line losses[7] of electricity during delivery from a generator to an end-user and T&D measures that reduce electricity use at the end-user, such as conservation voltage reduction (CVR)[8].

[7] T&D system losses (or "line losses") are typically defined as the difference between electricity generation to the grid and electricity sales. These losses are the fraction of electricity lost to resistance along the T&D lines, which varies depending on the specific conductors, the current, and the length of the lines. The Energy Information Administration (EIA) estimates that national electricity T&D losses average about 6 percent of the electricity that is transmitted and distributed in the U.S. each year.

[8] Volt/VAr optimization (VVO) refers to coordinated efforts by utilities to manage and improve the delivery of power in order to increase the efficiency of electricity distribution. VVO is accomplished primarily through the implementation of smart grid technologies that improve the real-time response to the demand for power. Technologies for VVO include load tap changers and voltage regulators, which can help manage voltage levels, as well as capacitor banks that achieve reductions in transmission line loss.

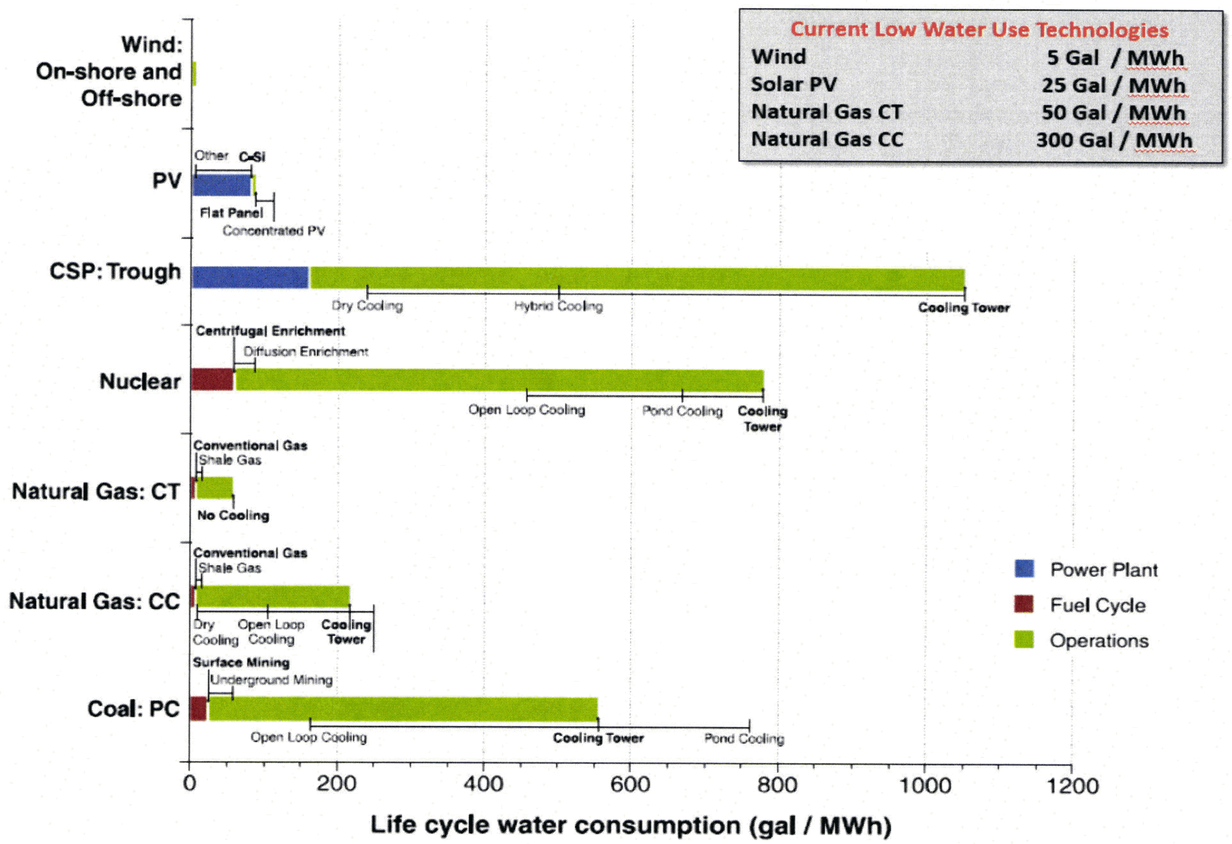
Planning for the Future of Energy Efficiency

UNSE's energy efficiency programs will continue to comply with the Arizona Energy Efficiency Standard that targets a cumulative energy savings of 22 % by 2020. In future planning cycles, UNSE plans to expand its energy efficiency resource portfolio to be compliant under the provisions of the CPP. UNSE plans to partner with states and local organizations to leverage the EPA's CEIP to identify opportunities to improve energy efficiency for low-and moderate income customers while supporting private sector and foundation initiatives. In the 2017 Final IRP, UNSE plans to highlight the company's strategy on how it plans to make this transition. This transition from the current Arizona Energy Efficiency standard to compliance under the CPP will play a key role in achieving low cost energy alternatives for UNSE's customers.

Power Generation and Water Impacts of Resource Diversification

The CPP achieves CO_2 emission reductions primarily by replacing generation from higher emitting coal-fired resources with a corresponding amount of generation from lower emitting NGCC plants and zero-emission renewable resources[9]. Fortunately, water use among these power generation technologies is analogous to their respective CO_2 emissions. See the Chart 2, below for average water consumption rates for various electricity generation technologies. Based on these water consumption rates, implementation of the CPP should result in lower water consumption for power generation overall.

Chart 2– Life Cycle Water Use for Power Generation[10]



However, unlike CO_2 emissions, water consumption has a much more localized environmental impact. The availability of water that is withdrawn from surface waters is highly dependent on precipitation and snow pack, as well as other uses. Similarly, the availability of water that is withdrawn from groundwater aquifers, as in the case of Gila River, is dependent on the recharge to and other withdrawals from the aquifer, but is also a function of the hydrogeological characteristics of the aquifer itself.

[9] Energy Efficiency is also an important tool for achieving the CO_2 emission reductions called for under the CPP.
[10] Adapted from Meldrum et. al. "Life cycle water use for electricity generation: a review and harmonization of literature estimates", published March 3, 2013, http://iopscience.iop.org/article/10.1088/1748-9326/8/1/015031

To the extent that the "replacement" power generation is located at or near to the coal-fired generation it is replacing, water availability will become less of an issue under CPP implementation. However, if the "replacement" power generation is located elsewhere, the water availability in that area may need to be evaluated.

There is over 6,000 MW of existing NGCC capacity located west of Phoenix, Arizona (in proximity to the Palo Verde Nuclear Generating Station) that is likely to see a significant increase in generation as a result of CPP implementation. While these generating facilities are expected to have the requisite legal rights to withdraw the amount of water necessary to meet expected higher demand for electricity, the risk associated with the cumulative impact of higher groundwater withdrawal on hydrogeological availability should be assessed. UNSE will include a qualitative assessment as part of the 2017 Final IRP.

Chapter 2

LOAD FORECAST

Introduction

In the IRP process, it is crucial to estimate the load obligations that existing and future resources will be required to meet for both short and long term planning horizons. As a first step in the development the resource plan, a long term load forecast was produced. This chapter will provide an overview of the anticipated long term load obligations at UNSE, a discussion of the methodology and data sources used in the forecasting process, and a summary of the tools used to deal with the inherent uncertainty currently surrounding a number of key forecast inputs.

Geographical Location and Customer Base

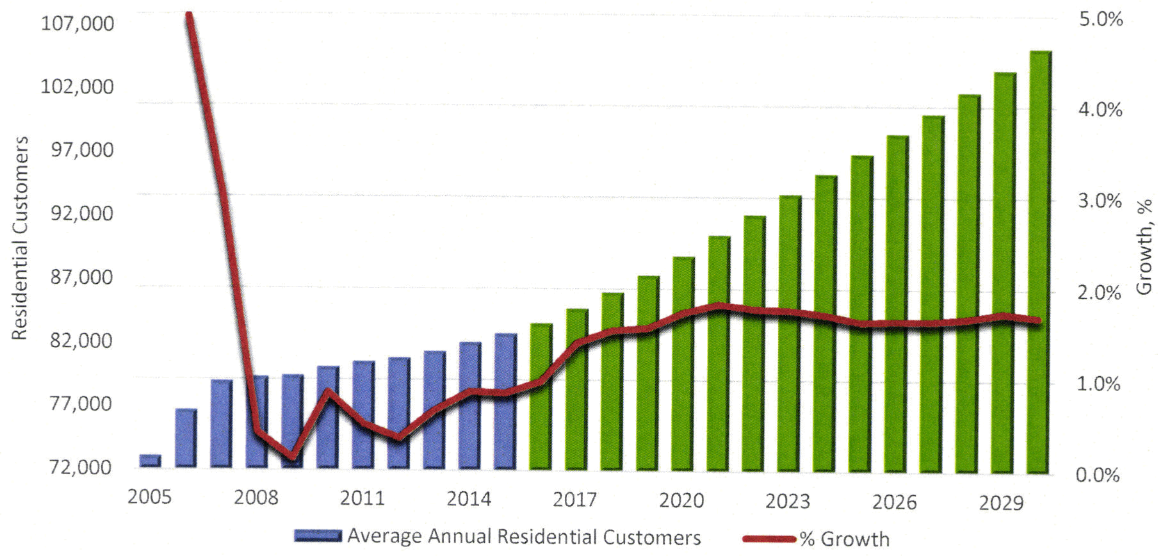
UNSE currently provides electricity to approximately 94,000 customers in two geographically distinct areas. In northwest Arizona, UNSE provides service to the majority of Mohave County. This segment of the service territory includes approximately 75,000 customers located primarily in the Kingman and Lake Havasu City areas. In addition to Mohave County, UNSE also provides service to the majority of Santa Cruz County in southern Arizona. This southern service territory includes approximately 19,000 customers located primarily in the Nogales area.

The two regions are very different both in terms of population and geography. For instance, Mohave County is estimated to have a current population of approximately 204,000 and has experienced an estimated 1.15% annual growth over the last decade, while Santa Cruz County is estimated to have a current population of approximately 47,000, and has grown at an estimated 1.14% annual rate over the same period. In addition to the varying population dynamics, the geography and weather of the two service areas are also distinctly different. For example, Lake Havasu City sits at an elevation of approximately 735 feet, while Nogales is located in mountainous terrain and sits at 3,823 feet. The differences in population demographics, topography, and weather result in distinct patterns of demand, consumption, and customer growth within each region that must be taken into account during the planning process.

While the economic climate has slowed population growth significantly in recent years, UNSE's service areas are still expected to experience significant growth after the recessionary environment in Arizona subsides. This anticipated growth will likely require the acquisition of additional resources in order to provide service to an increasing customer base.

Chart 3 summarizes the historical and projected UNSE residential customer growth from 2005-2030.

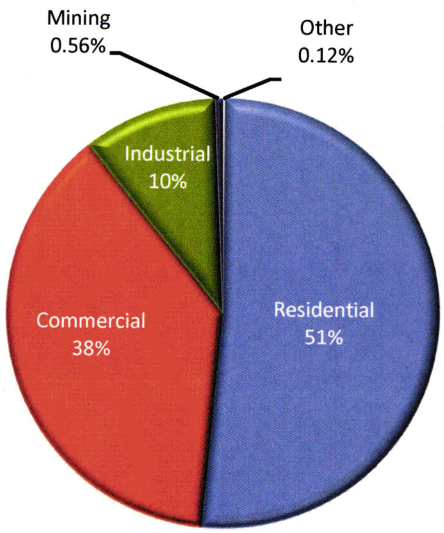
Chart 3 - UNSE Residential Customer Growth 2005-2030



Retail Sales by Rate Class

In 2015, UNSE experienced retail peak demand of approximately 400 MW while generating approximately 1,600 GWh of sales. Approximately 89% of 2015 retail sales were generated by the residential and commercial rate classes, and approximately 11% generated by the industrial and mining rate classes. Chart 4 details estimated 2016 UNSE retail sales by rate class.

Chart 4 – Estimated 2016 Retail Sales % by Rate Class



Load Forecast Process

Methodology

The load forecast presented in this PIRP was derived using a "bottom up" approach. A monthly energy forecast was prepared for each of the major rate classes (residential, commercial, industrial, and mining). Widely varying customer usage patterns and weather in Mohave and Santa Cruz counties, as well as significant differences between customer usage and weather in the Kingman area and the Lake Havasu City area within the Mohave service territory require that the forecasts be further segmented into three distinct geographical projections. However, the individual methodologies fall into two broad categories:

1) For the residential and commercial classes, forecasts are produced using statistical models. Inputs may include factors such as historical usage, weather (e.g. average temperature and dew point), demographic forecasts (e.g. population growth), and economic conditions (e.g. gross county product and disposable income).

2) For the industrial and mining classes, forecasts are produced for each individual customer on a case by case basis. Inputs include historical usage patterns, information from the customers themselves (e.g. timing and scope of expanded operations), and information from internal company resources working closely with the mining and industrial customers.

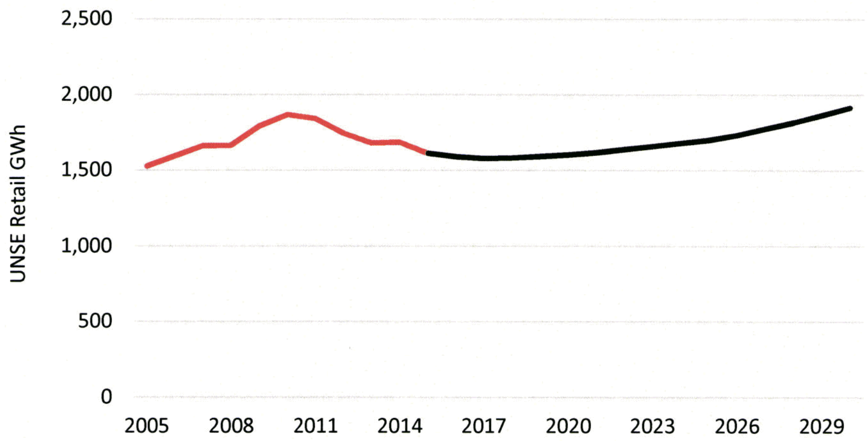
After the individual monthly forecasts are produced, they are aggregated (along with any remaining miscellaneous consumption falling outside the major categories) to produce a monthly energy forecast for the company.

After the monthly energy forecast for the company was produced, the anticipated monthly energy consumption was used as an input for another statistical model used to estimates the peak demand for each month based on the historical relationship between consumption and demand in the month in question. Annual peak demand was then calculated by simply taking the maximum monthly peak demand for each year in the forecast period.

Retail Energy Forecast

As illustrated in Chart 5, UNSE's retail sales, in aggregate, are expected to be relatively flat over the next few years. Total energy sales are expected to steadily grow throughout the forecast horizon.

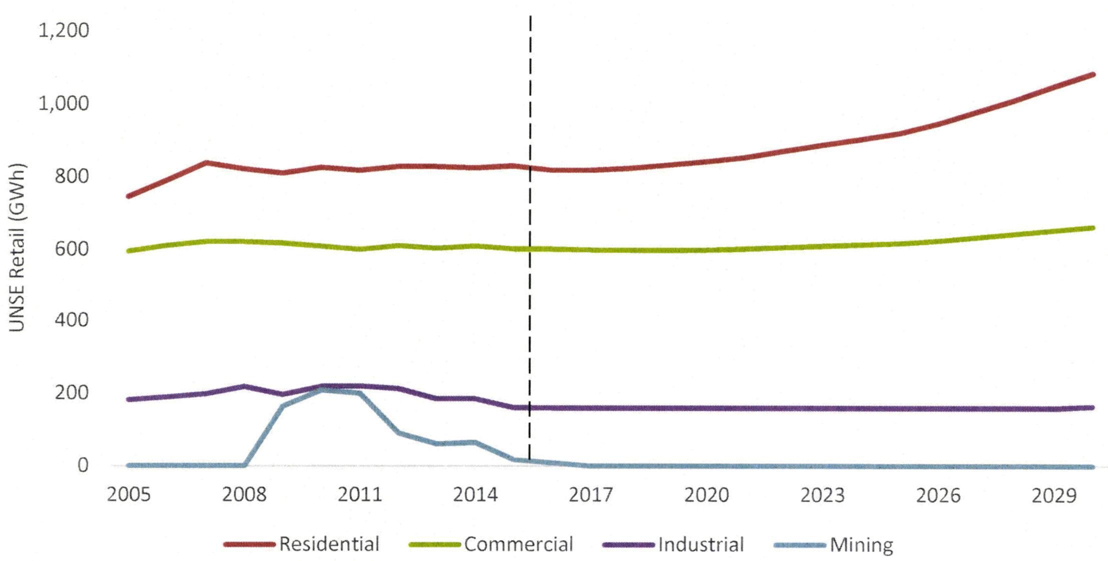
Chart 5 - Retail Energy Sales



Retail Energy Forecast by Rate Class

As illustrated in Chart 6 the load forecast assumes significant, steady energy sales growth at UNSE throughout the planning period. However, the growth rates vary significantly by rate class. The energy sales trends for each major rate class are detailed in Chart 6. The loss of mining sales due to economic weakness can be seen in Chart 6.

Chart 6 - Retail Energy Sales by Rate Class

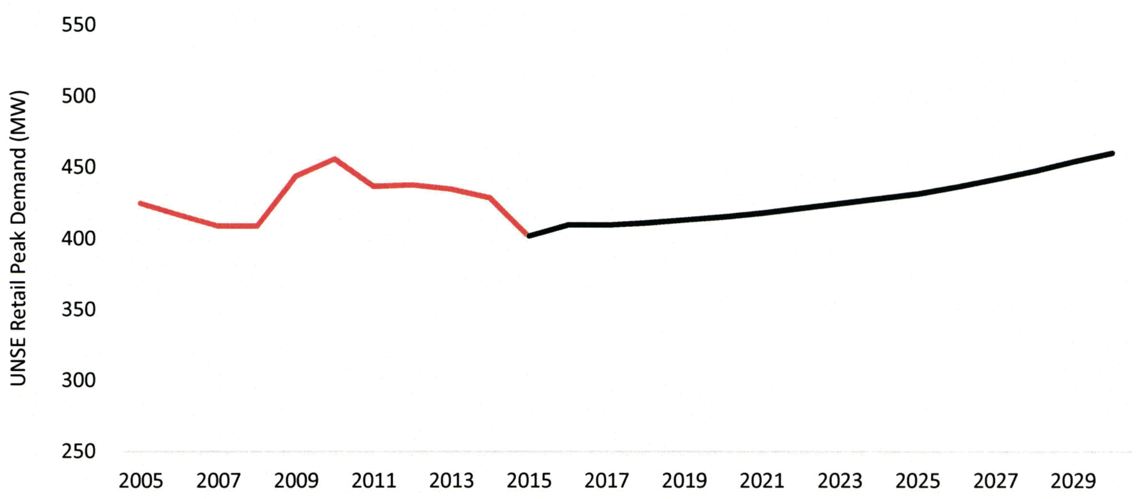


Peak Demand Forecast

As illustrated in Chart 7, UNSE's peak demand is expected to increase throughout the forecast period.

Note that all references to peak demand are "coincidental" peak system demand (i.e. the highest demand seen simultaneously in the Mohave and Santa Cruz service areas). Due to geography, the two service areas typically experience individual service area peaks at different times with the Santa Cruz peak typically occurring in June and the Mohave peak typically occurring in July or August. Because Mohave County generates much higher demand (and energy sales), the UNSE coincidental system peak also typically occurs in July or August.

Chart 7 - Reference Case Peak Demand



Data Sources Used in Forecasting Process

As outlined above, the reference case forecast requires a broad range of inputs (demographic, economic, weather, etc.) For internal forecasting processes, UNSE utilizes a number of sources for these data:

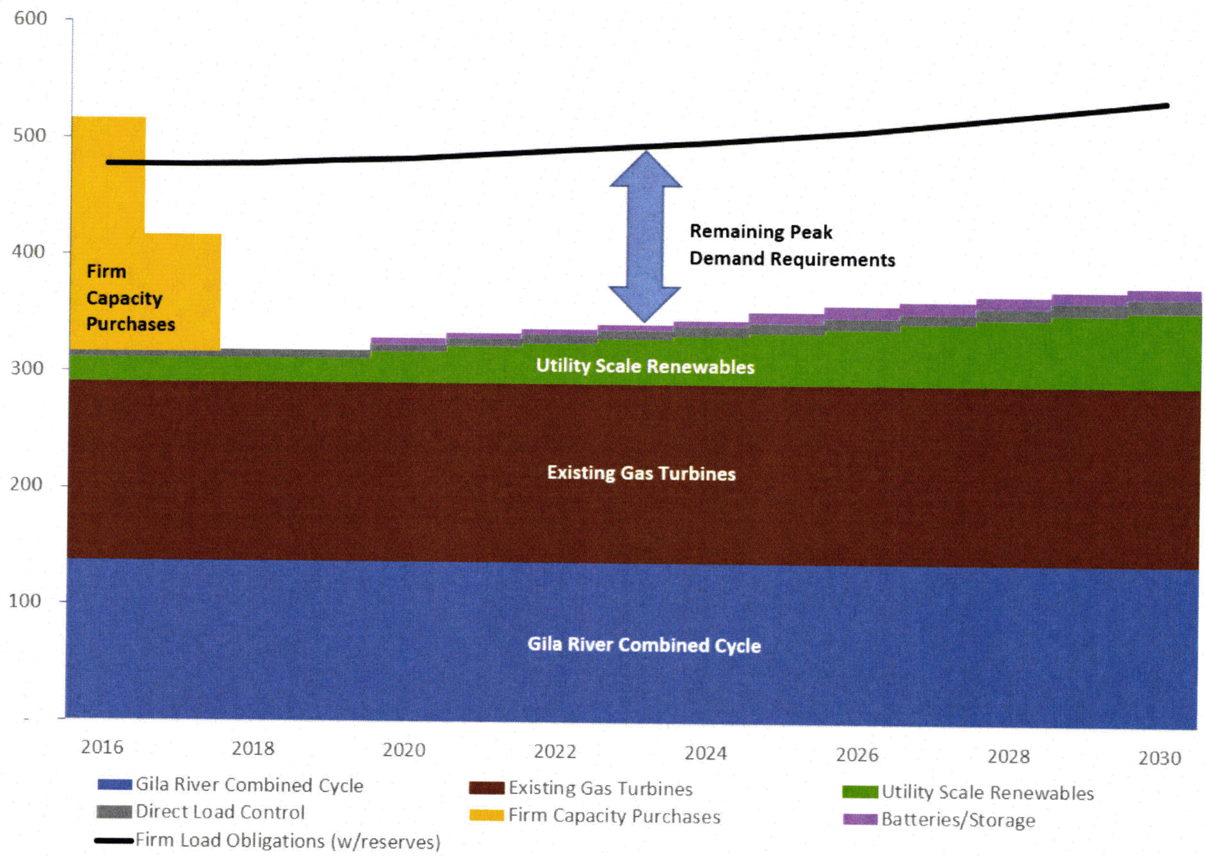
- IHS Global Insight
- The University of Arizona Forecasting Project
- Arizona Department of Commerce
- U.S. Census Bureau
- NOAA
- Weather Underground

Chapter 3

Load and Resources

The loads and resources chart shown below illustrates how UNSE's firm load obligations are met currently. The firm load obligations represent UNSE's retail demand less energy efficiency and distributed generation plus a 15% planning reserve margin. The 2017 Final IRP will evaluate the remaining peak demand requirements (shown below) to determine a diverse portfolio mix.

Chart 8 – UNSE Loads and Resources



Future Load Obligations

The tables on the next two pages provide a data summary on UNSE's loads and resources. Table 2 details UNSE's projected firm load obligations which include retail demand, less energy efficiency and distributed generation plus planning reserves.

Table 2 - Firm Load Obligations, System Peak Demand (MW)

Demand, MW	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	226	230	234	240	245	250	257	262	267	272	279	286	292	299	305
Commercial	166	168	170	172	174	176	179	180	181	183	184	186	186	186	187
Industrial	44	45	45	46	47	47	47	47	47	47	47	47	46	45	46
Mining	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gross Retail Peak Demand	**440**	**443**	**451**	**458**	**466**	**474**	**482**	**489**	**496**	**503**	**511**	**518**	**524**	**531**	**538**
Distributed Generation	-7	-8	-9	-10	-11	-11	-12	-12	-13	-13	-13	-14	-14	-14	-14
Energy Efficiency	-23	-25	-30	-35	-40	-45	-49	-52	-55	-58	-61	-63	-63	-63	-64
Net Retail Peak Demand	**410**	**410**	**411**	**413**	**416**	**418**	**422**	**425**	**428**	**432**	**437**	**442**	**448**	**454**	**460**
Firm Wholesale Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
System Losses	32	32	32	32	33	33	33	33	34	34	34	35	35	36	36
Total Firm Load Obligations	**442**	**442**	**443**	**446**	**448**	**451**	**455**	**458**	**462**	**466**	**471**	**477**	**483**	**490**	**496**
Reserve Margin	74	-25	-126	-128	-120	-117	-117	-117	-117	-111	-112	-114	-115	-117	-120
Reserve Margin, %	17%	-6%	-28%	-29%	-27%	-26%	-26%	-25%	-25%	-24%	-24%	-24%	-24%	-24%	-24%

Resource Capacity

Table 3 details UNSE's current resource portfolio based on a resource's capacity contribution to system peak.

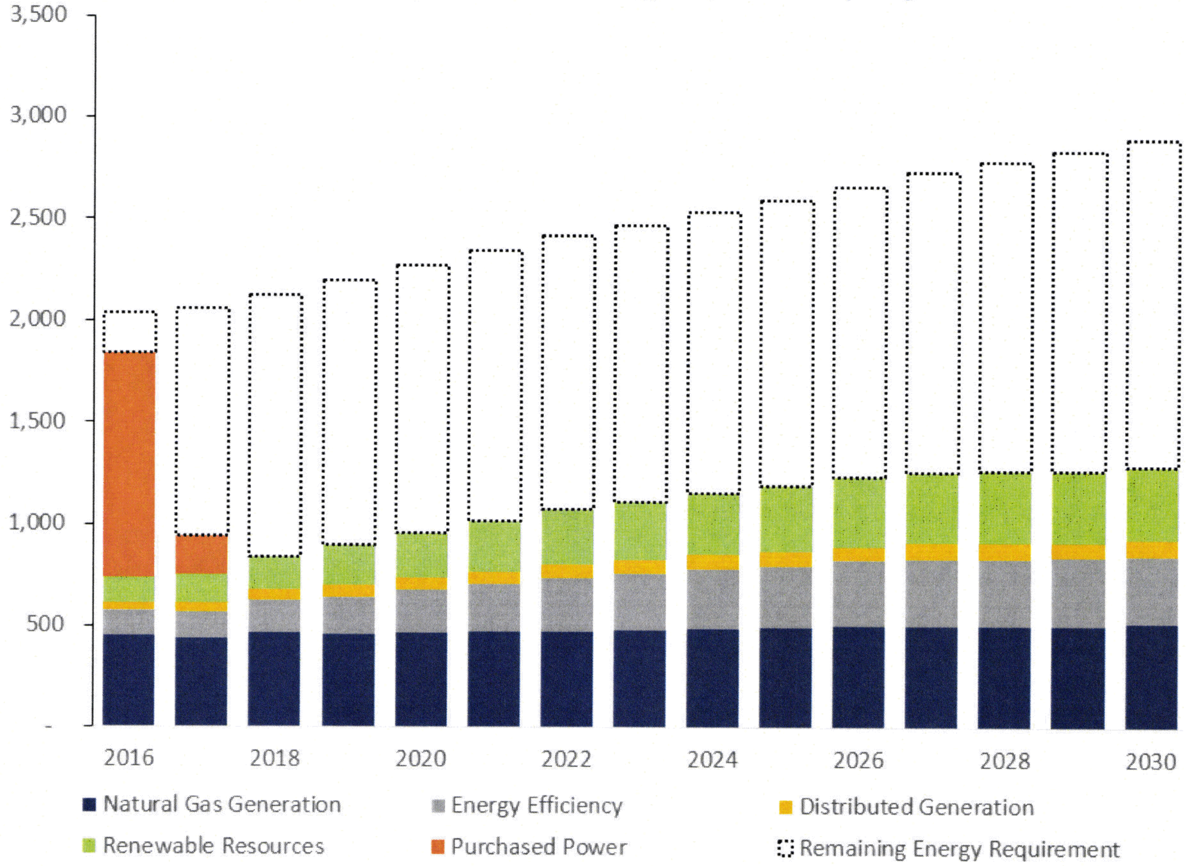
Table 3 – Capacity Resources, System Peak Demand (MW)

Firm Resource Capacity (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gila River Power Station	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5	137.5
Black Mountain	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Valencia	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5	63.5
Total Natural Gas Resources	291	291	291	291	291	291	291	291	291	291	291	291	291	291	291
Utility Scale Renewables	22	22	22	22	27	32	35	39	42	45	49	53	57	62	65
Demand Response	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11
Total Renewable & EE Resources	25	26	26	27	32	38	42	46	49	53	58	62	67	72	76
Short-Term Market Resources	200	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Storage Resources	0	0	0	0	5	5	5	5	5	10	10	10	10	10	10
Total Firm Resources	516	417	317	318	328	334	338	342	345	354	359	363	368	373	377

Expected Annual Energy

Chart 9 shows the expected energy contribution required to meet UNSE's firm load obligations by year and resource type. In 2016, UNSE's energy portfolio is comprised of approximately 65% purchased power and 22% natural gas resources. The balance of the energy required is provided by EE, DG and renewable PV and wind. By 2030, 50% of UNSE's energy portfolio is unsubscribed though the energy efficiency and renewable standard will be met. In the 2017 Final IRP, UNSE will present a balanced and diversified portfolio to meet future energy needs.

Chart 9 -Expected Annual Energy Requirements (GWh)



Community Scale Renewables and Distributed Generation

Community Scale Renewables

UNSE is moving toward a diverse portfolio of renewable resources that complies with the Arizona Renewable Energy Standard ("RES"). UNSE is committed to meet the renewable energy standard goals, which requires UNSE to obtain renewable energy which is equivalent to 6% of its 2016 retail load requirement and growing to 15% by 2025. In the first quarter of 2014, UNSE added 7.2 MW (DC) of solar PV in Rio Rico, Arizona. This resource addition brings the total renewable capacity to nearly 30 MW. The addition of Red Horse Solar (see Table 4 below) will put UNSE above compliance in 2016 by approximately 2%.

EXISTING RENEWABLE RESOURCES

Overview

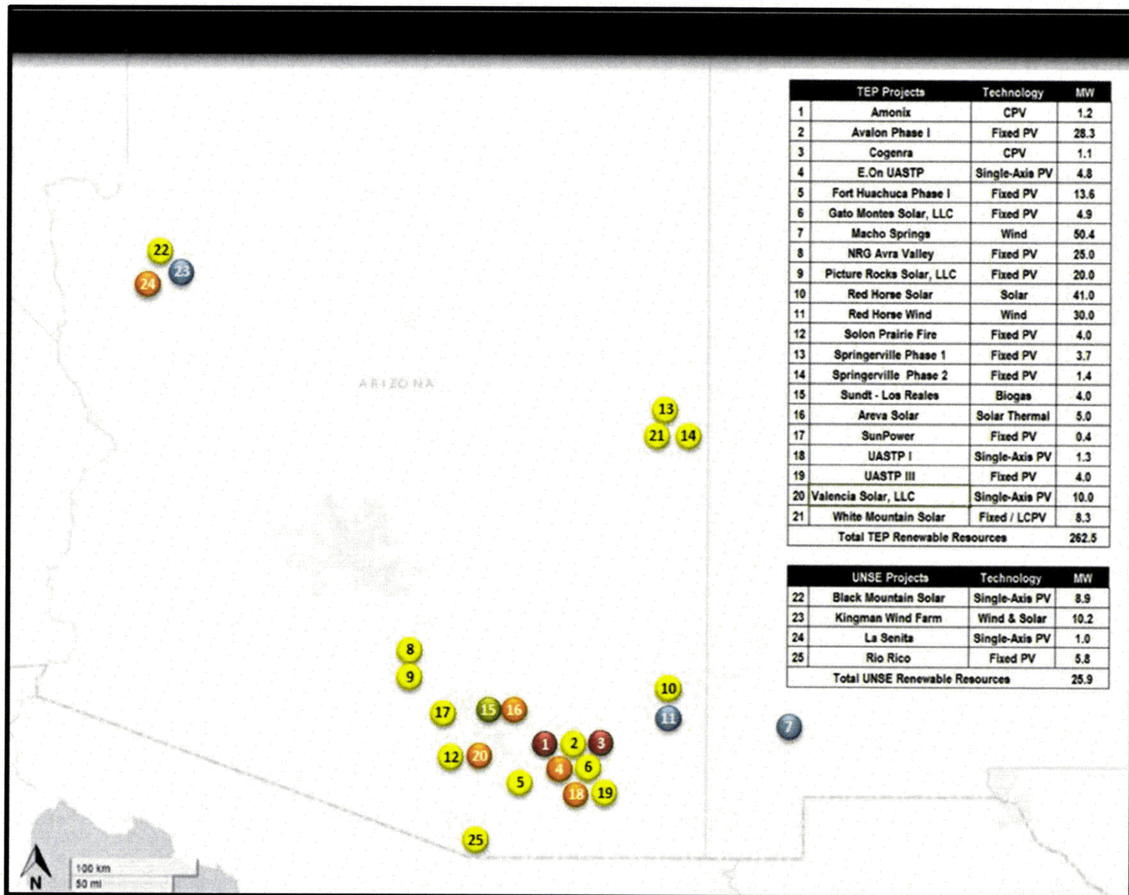
Over the last several years, UNSE has worked with third-party contractors to develop three new renewable resource projects within UNSE's service territory. In addition, the Company is currently working with Torch Renewables to develop a new solar fixed PV project located in Willcox, Arizona. Table 4 below provides an overview on UNSE renewable projects.

Table 4 – UNSE's Renewable Resources (Existing and Planned)

Resource- Counterparty	Owned/PPA	Technology	Location	Operator-Manufacturer	Completion Date	Capacity MW
Western Wind	PPA	Wind	Kingman, AZ	Western Wind	Sept 2011	10.3
La Senita School	Owned	SAT PV	Kingman, AZ	Solon	Nov 2011	0.98
Black Mountain	PPA	SAT PV	Kingman, AZ	Solon	Jun 2012	8.9
Rio Rico	Owned	PV	Rio Rico, AZ	Gehrlicher	Mar 2014	5.76
Red Horse Solar (Future)	PPA	SAT PV	Willcox, AZ	Torch Renewables	Q2 2016	30
UNSE Owned Solar	UNSE	TBD	Kingman, AZ	TBD	Q4 2016	5

Notes: PPA – Purchased Power Agreement – Energy is purchased from a third party provider.
SAT PV – Single Axis Tracking Photovoltaic
PV – Fixed Panel Photovoltaic

Locations of UNS Renewable Projects



	TEP Projects	Technology	MW
1	Amonix	CPV	1.2
2	Avalon Phase I	Fixed PV	28.3
3	Cogenra	CPV	1.1
4	E.On UASTP	Single-Axis PV	4.8
5	Fort Huachuca Phase I	Fixed PV	13.6
6	Gato Montes Solar, LLC	Fixed PV	4.9
7	Macho Springs	Wind	50.4
8	NRG Avra Valley	Fixed PV	25.0
9	Picture Rocks Solar, LLC	Fixed PV	20.0
10	Red Horse Solar	Solar	41.0
11	Red Horse Wind	Wind	30.0
12	Solon Prairie Fire	Fixed PV	4.0
13	Springerville Phase 1	Fixed PV	3.7
14	Springerville Phase 2	Fixed PV	1.4
15	Sundt - Los Reales	Biogas	4.0
16	Areva Solar	Solar Thermal	5.0
17	SunPower	Fixed PV	0.4
18	UASTP I	Single-Axis PV	1.3
19	UASTP III	Fixed PV	4.0
20	Valencia Solar, LLC	Single-Axis PV	10.0
21	White Mountain Solar	Fixed / LCPV	8.3
	Total TEP Renewable Resources		262.5

	UNSE Projects	Technology	MW
22	Black Mountain Solar	Single-Axis PV	8.9
23	Kingman Wind Farm	Wind & Solar	10.2
24	La Senita	Single-Axis PV	1.0
25	Rio Rico	Fixed PV	5.8
	Total UNSE Renewable Resources		25.9

Distributed Generation

By the end of 2015, UNSE had approximately 20 MW of rooftop solar PV and solar hot water heating capacity. Distributed generation is expected to supply at least 40 GWh of energy in 2016.

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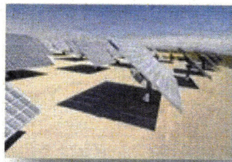
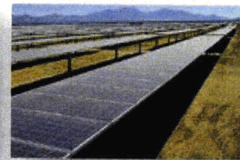
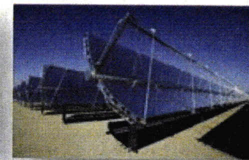
Overview of UNS Renewable Portfolio



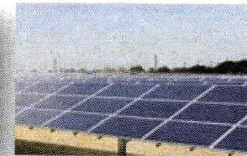
Amonix
Dual Axis Concentrated PV
1.2 MW



Avalon
Fixed PV
28.3 MW

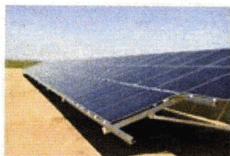


Cogenra
SAT Concentrated Thermal PV
1.1 MW



E. ON.
Single Axis Tracking PV
4.8 MW

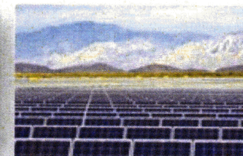
Fort Huachuca
Fixed PV
13.6 MW



Gato Montes Solar
Fixed PV
4.9 MW

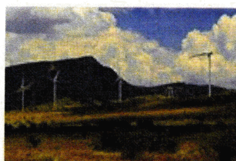
Macho Springs
Wind
50.4 MW

NRG Avra Valley
Fixed PV
25 MW

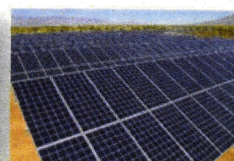


Picture Rocks Solar
Fixed PV
20 MW

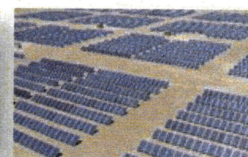
Red Horse Solar
Fixed PV
40 MW



Red Horse Wind
Wind
30 MW

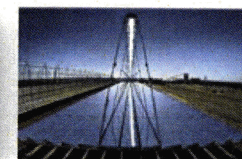


Solon Prairie Fire
Fixed PV
4.0 MW

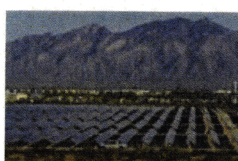


Springerville
Fixed PV
5.1 MW

Los Reales Landfill Gas
Biogas
4.0 MW

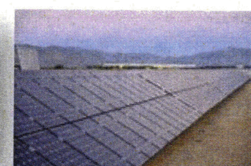


Areva Solar
Concentrated Solar Thermal
5.0 MW

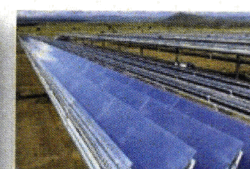


Valencia Solar
Single Axis Tracking PV
10 MW

Solon UASTP 1
Single Axis Tracking PV
1.3 MW
500 kW of Lithium-Ion
Battery Storage



Solon UASP 3
Fixed PV
4.0 MW



White Mountain Solar
SAT Concentrated Thermal PV
8.3 MW

Kingman Wind & Solar
Wind & Fixed PV
10.2 MW

Energy Efficiency

Overview

This section is an overview of the electric Demand-Side Management ("DSM") programs that target the residential, commercial and industrial ("C&I") sectors, as well as their associated proposed implementation costs, savings, and benefit-cost results.

UNSE recognizes that energy efficiency can be a cost-effective way to reduce our reliance on fossil fuels. UNSE offers a variety of energy saving options for customers, from simple consultation to incentives that encourage both homeowners and businesses to invest in efficient heating and cooling and other energy efficiency upgrades.

UNSE, with input from other parties such as Navigant Consulting, Inc. ("Navigant") and the Southwest Energy Efficiency Project ("SWEEP"), has designed a comprehensive portfolio of programs to deliver electric energy and demand savings to meet the annual DSM energy savings goals outlined in the Standard. These programs include incentives, direct-install and buy-down approaches for energy efficient products and services; educational and marketing approaches to raise awareness and modify behaviors; and partnerships with trade allies to apply as much leverage as possible to augment the return of rate-payer dollars invested.

Through UNSE's DSM programs UNSE has made great strides toward meeting the aggressive goals in the Standard. The Standard calls on investor-owned electric utilities in Arizona to increase the kilowatt-hour savings realized through customer ratepayer-funded energy efficiency programs each year until the cumulative reduction in energy achieved through these programs reaches 22 percent by 2020.

Current Implementation Plan, Goals, and Objectives

UNSE's high-level energy efficiency-related goals and objectives are as follows:

- Implement cost-effective energy efficiency programs
- Design and implement a diverse group of programs that provide opportunities for participation for all customers
- When feasible, maximize opportunities for program coordination with other efficiency programs (e.g., Southwest Gas Corporation, Arizona Public Service Corporation) to yield maximum benefits
- Maximize program energy savings at a minimum cost by striving to achieve comprehensive cost-effective savings opportunities
- Provide UNSE customers and contractors with web access to detailed information on all efficiency programs (residential and commercial) for electricity savings opportunities at www.uesaz.com
- Expand the energy efficiency infrastructure in the state by increasing the number of available qualified contractors through training and certification in specific fields
- Use trained and qualified trade allies such as electricians, HVAC contractors, builders, architects and engineers to transform the market for efficient technologies
- Educate customers on behavior modifications that enable them to use energy more efficiently.

Program Portfolio Overview

As demonstrated in Table 5, UNSE's portfolio of programs can be divided into residential, commercial, behavioral, and support sectors with administrative functions providing support across all program areas. With the Commission's approval of UNSE's 2015/2016 EE Plan, UNSE has added measures within existing programs including energy star appliances , HVAC, and lighting measures.

Table 5 – UNS Electric Portfolio of Programs

Residential Sector	Appliance Recycling
	Energy Star Appliance Program
	Existing Homes
	Low Income Weatherization
	Multi-Family Direct Install
	New Construction
	Shade Trees
Behavioral Sector	Community Education
	K-12 Energy Education
Commercial & Industrial Sector	Bid for Efficiency
	C&I Facilities/Schools
	C&I Demand Response
	Retro-Commissioning
Support Sector	Education and Outreach
	Energy Codes & Standards Enhancement

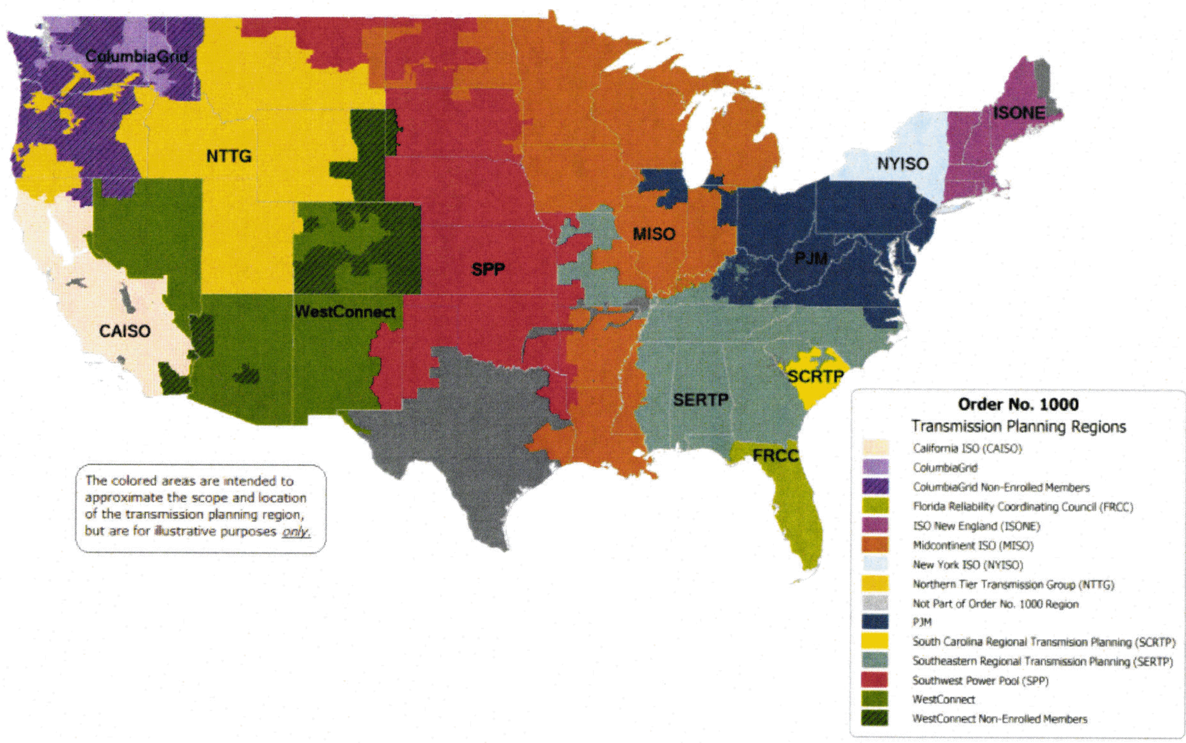
Transmission

Overview

Transmission resources are a key element in UNSE's resource portfolio. Adequate transmission capacity must exist to meet UNSE's existing and future load obligations. UNSE's resource planning and transmission planning groups coordinate their planning efforts to ensure consistency in development of its long-term planning strategy. On a statewide basis, UNSE participates in the ACC's Biennial Transmission Assessment ("BTA") which produces a written decision by the ACC regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of Arizona in a reliable manner.

UNSE actively participates in the regional transmission planning and cost allocation process of WestConnect as an enrolled member of the Transmission Owners with Load Service Obligations ("TOLSO") sector in compliance with FERC Order No. 1000 ("FERC Order 1000"). This final rule reforms FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. WestConnect is composed of utility companies providing transmission of electricity in the western United States working collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to the western wholesale electricity market.

Figure 4 – FERC Order 1000 Transmission Planning Regions



Since FERC Order 1000, WestConnect went through its first one-year regional planning and cost allocation process upon completion and approval of the 2015 Regional Transmission Plan in December 2015. No project submittals, and therefore no cost allocation was required since no regional transmission needs were identified in this abbreviated 2015 cycle.

Preparation for the first WestConnect biennial regional transmission planning and cost allocation process covering the period January 1, 2016 through December 31, 2017 began in the last quarter of 2015. Preparation included initiation of the 2016-17 Regional Study Plan process and acceptance of scenarios to be evaluated for inclusion in the study plan occurred by December 31, 2015. WestConnect conducts an assessment of transmission planning models incorporating these scenarios to identify the need for new transmission. The key deliverable is a regional transmission plan that selects regional transmission projects to meet identified reliability, economic, public policy, or combination thereof, transmission needs.

To assist with Arizona's CPP state planning efforts, UNSE participated with APS, SRP, Southwest Transmission Cooperative and TEP on a proposal to coordinate development of its CPP compliance plan, and prepared and submitted a joint Arizona Utility Group ("AUG") study request to WestConnect to be included in the 2016-17 Regional Planning Process. Working through the regional planning process is the most efficient method of achieving a credible outcome because it is accomplished in coordination with the other three western Planning Regions (California Independent System Operator ("CAISO"), Columbia Grid and Northern Tier Transmission Group) and therefore in coordination with other states. A key objective is to have access to the WestConnect power flow base case to perform a more credible reliability analysis on the Arizona transmission system assessing the impact of the CPP and meeting BTA planning requirements.

Chapter 4

EMERGING TECHNOLOGIES

Small Modular Nuclear Reactors

Small modular nuclear reactors ("SMR"), approximately one-third the size of current nuclear plants, are compact in size (300 MW or less) and are expected to offer many benefits in design, scale, and construction (relative to the current fleet of nuclear plants) as well as economic benefits. As the name implies, being modular allows for factory construction and freight transportation to a designated site. The size of the facility can be scaled by the number of modules installed. Capital costs and construction times are reduced because the modules are self-contained and ready to be "dropped-in" to place.

A World Nuclear Association 2015 report on SMR standardization of licensing and harmonization of regulatory requirements, said that the enormous potential of SMRs rests on a number of factors:

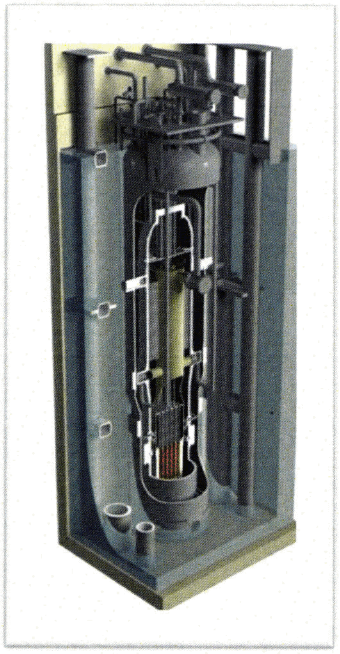
- Because of their small size and modularity, SMRs could almost be completely built in a controlled factory setting and installed module by module, improving the level of construction quality and efficiency.
- Their small size and passive safety features make them favorable to countries with smaller grids and less experience of nuclear power.
- Size, construction efficiency and passive safety systems (requiring less redundancy) can lead to easier financing compared to that for larger plants.
- Moreover, achieving 'economies of series production' for a specific SMR design will reduce costs further.

The World Nuclear Association lists the features of an SMR, including:

- Small power, compact architecture and employment of passive concepts (at least for nuclear steam supply system and associated safety systems). Therefore there is less reliance on active safety systems and additional pumps, as well as AC power for accident mitigation.
- The compact architecture enables modularity of fabrication (in-factory), which can also facilitate implementation of higher quality standards.
- Lower power leading to reduction of the source term as well as smaller radioactive inventory in a reactor (smaller reactors).
- Potential for sub-grade (underground or underwater) location of the reactor unit providing more protection from natural (**e.g.** seismic or tsunami according to the location) or man-made (**e.g.** aircraft impact) hazards.

- The modular design and small size lends itself to having multiple units on the same site.
- Lower requirement for access to cooling water – therefore suitable for remote regions and for specific applications such as mining or desalination.
- Ability to remove reactor module or in-situ decommissioning at the end of the lifetime

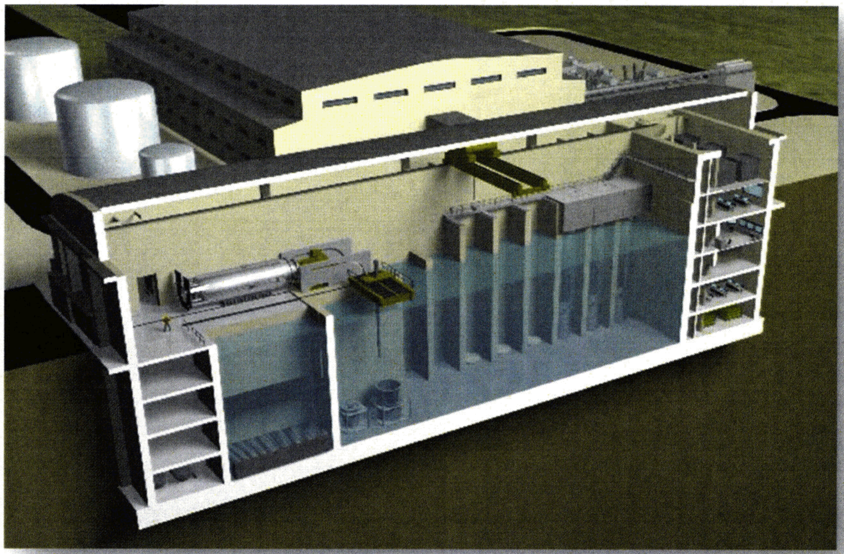
The World Nuclear Association website has detailed information related to SMRs. The website is located at: http://www.world-nuclear.org/info/nuclear-fuel-cycle/power-reactors/small-nuclear-power-reactors/



50 MWe NuScale Power Module

NuScale Power™ is developing 50 MWe modules that can be scaled up to 600 MWe (12 modules). The scalability of SMRs allows for small utilities like UNSE to consider their viability while lessening the financial risk. In December of 2013, NuScale was awarded a grant by the Department of Energy ("DOE") that would cover half (up to $217 million) to support development and receive certification and licensing from the Nuclear Regulatory Commission ("NRC") on a single module.

In the fall of 2014, NuScale signed teaming agreements with key utilities in the Western region, which include Energy Northwest in Washington State and the Utah Association of Municipal Power Systems ("UAMPS"), representing municipal power systems in Utah, Idaho, New Mexico, Arizona, Washington, Oregon, and California. This initial project, known as the UAMPS Carbon Free Power Project, would be sited in eastern Idaho and is being developed with partners UAMPS, which will be the plant owner, and Energy Northwest, which will be the operator. The team expects that the 12-module SMR will be operation in 2024.



NuScale Cross-section of Typical NuScale Reactor Building

Reciprocating Internal Combustion Engines

Reciprocating Internal Combustion Engines ("RICE") are simply combustion engines that are used in automobiles, trucks, railroad locomotives, construction equipment, marine propulsion, and backup power applications. Modern combustion engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICE are characterized by the type of combustion: spark-ignited, like in a typical gas powered vehicle or compression-ignited, also known as diesel engines.

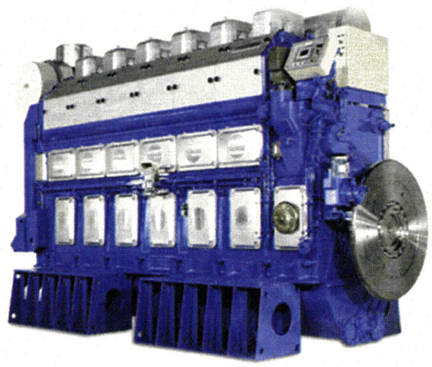


Figure 5 – Wartsila-50DF

An emerging and potentially beneficial use of these engines is in large-scale electric utility generation. The combustion engine is not a new technology but emerging advances in efficiency and the need for fast-response generation make it a viable option to stabilize variable and intermittent electric demand and resources. RICE has demonstrated the following benefits;

- Fast Start Times – The units are capable of being on-line at full load within 5 minutes. The fast response is ideal for cycling operation. RICE can be used to 'smooth' out intermittent resource production and variability.

- Run Time - The units do not require to be maintained at full load or shut down for extended periods of time. After shut down, the unit must be down for 5 minutes, at a minimum to allow for gas purging.

- Reduced O&M – Cycling the unit has no impact on the wear of RICE. The unit is impacted by hours of operation and not by starts and cycling operations as is the case with combustion turbines.

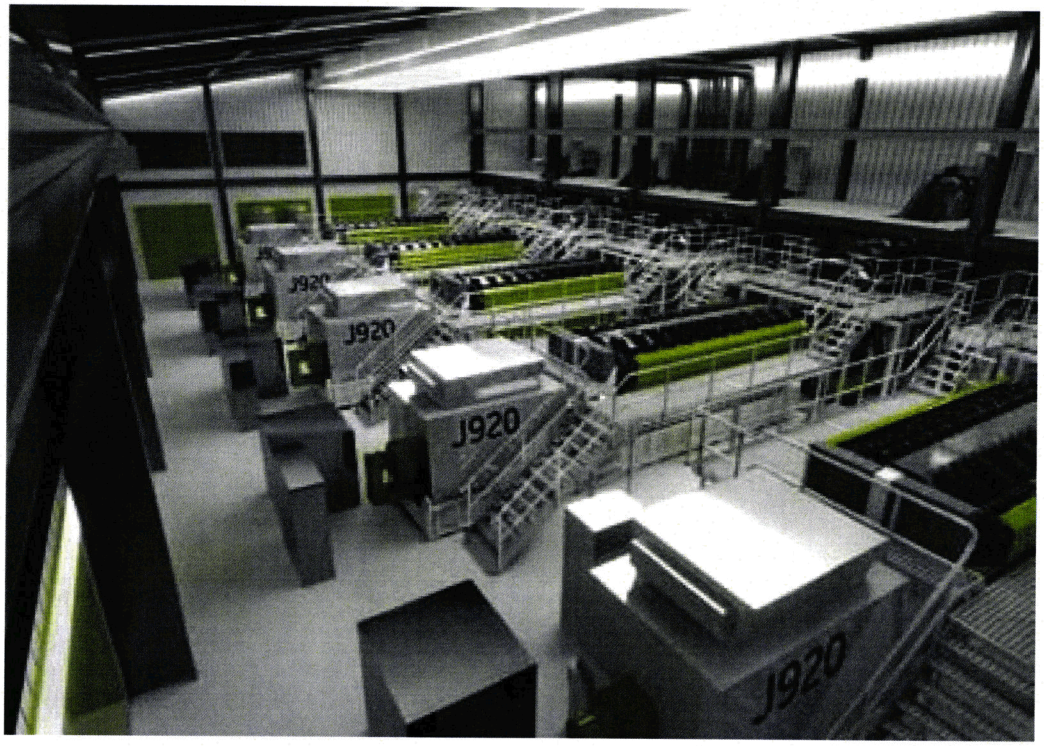
- Fast Ramping – At start, the unit can ramp to full load in 2 minutes on a hot start and in 4 minutes on a warm start. Once the unit is operational, it can ramp between 30% and 100% load in 40 seconds. This ramping is comparable to the rate that many hydro facilities can ramp at.

- Minimal Ambient Performance Degradation – Compared to Aeroderivative and Frame type combustion turbines, RICE output and efficiency is not as drastically impacted by temperature. The site altitude does not significantly impact output on RICE below 5,000 feet.

- Gas Pressure – RICE can run on low pressure gas, as low as 85 PSI. Most CT's require a compressor for pressure at 350 PSI.
- Reduced Equivalent Forced Outage Rate ("EFOR") – Each RICE has an EFOR of less than 1%. A facility with multiple RICE will have a combined EFOR that is exponentially less by a factor of the number of units at the facility.
- Low Water Consumption – RICE use a closed-loop cooling system that requires minimal water usage.
- Modularity – Each RICE unit is built at approximately 2 to 20 MWs and is shipped to the site.

An intriguing application for RICE is its potential for regulating the variability and intermittency of renewable resources. In the final IRP, UNSE will explore the possibility of natural gas powered RICE in its proposed scenarios.

Figure 6 – Reciprocating Internal Combustion Engine Facility



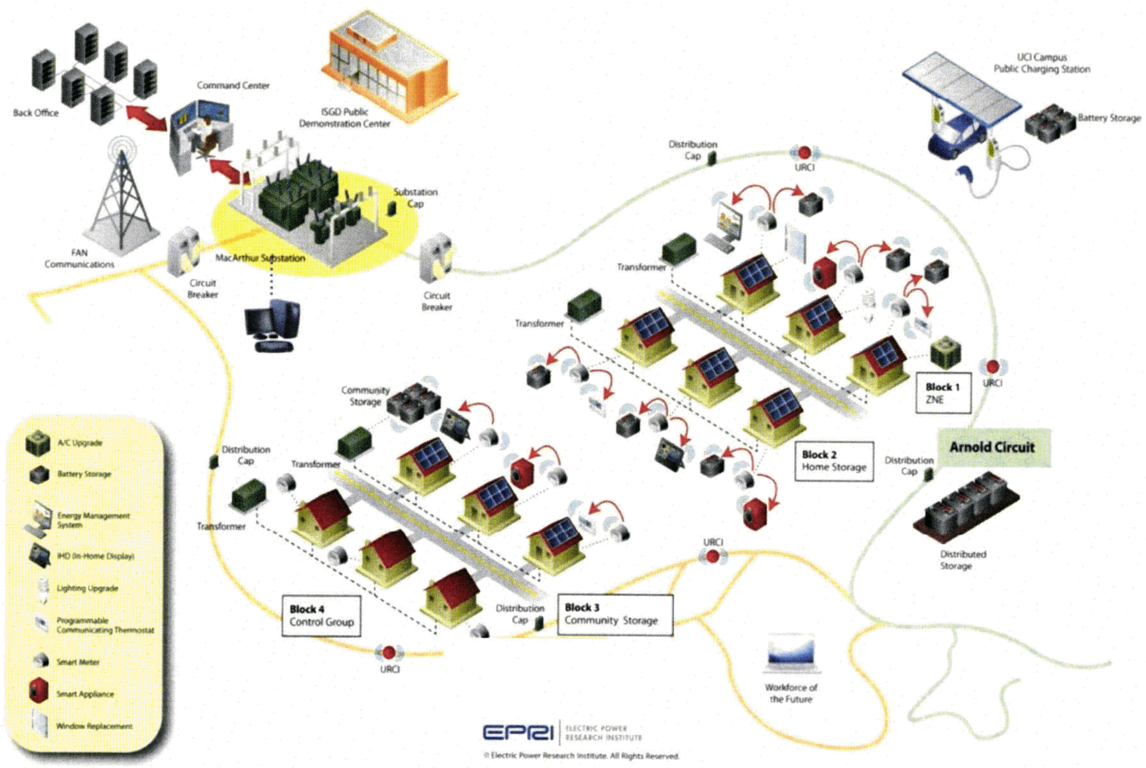
DELIVERY TECHNOLOGY

The Future of the Distribution Grid

Changes in the supply, demand, and delivery of electricity are remodeling electric distribution systems at most North American utilities. Distributed Energy Resources ("DERs") are leading many of these changes. By creating energy supply in new, small, intermittent, and distributed locations across the grid, DERs have required new levels of system flexibility. DERs have also created new opportunities for electric utilities to improve performance, to lower costs, and to improve customer satisfaction.

To accommodate DERs and other innovations, electric utilities need to do more than make their distribution systems bigger. Instead, utilities need to make their distribution systems smarter. Smart distribution systems provide flexibility, capability, speed and resilience. To achieve new levels of performance, these smart distribution systems include new types of software, networks, sensors, devices, equipment, and resources. To achieve new levels of economic value, these smart distribution systems operate according to new strategies and metrics. With more distributed generation resources being deployed on UNSE's distribution system, higher demands and lower energy consumption is occurring today. This puts demands on the transmission and distribution systems that were not contemplated in the original designs and requirements of the system. To meet these new demands, new methods and technology needs to be developed and implemented. UNSE is intending to utilize technology to add more sensing and measurement devices and new methods for managing and operating the distribution system. This approach turns a distribution feeder into an effective micro grid system.

Figure 7 – Smart Grid Systems



With increased demand and lower energy consumption, new techniques and strategies need to be developed and implemented to effectively manage costs. By adding additional measurement and sensing capabilities the situational awareness of the distribution system will be increased. The situational awareness allows for real time operations and planning opportunities for efficiency and productivity changes. To utilize the existing distribution system more efficiently, UNSE is investigating the use of DERs, energy storage, energy efficiency, and targeted demand response capabilities in conjunction with optimization software to reduce the infrastructure additions required due to higher customer demand. This strategy is much different than how the distribution system has been managed in the past. We are now using a bottom up planning and design process that needs to be integrated with the IRP process. New tools and capabilities will be required as a result of the new opportunities and capabilities envisioned.

At the core of these changes is the need for a communications network that allows for intelligent electronic devices to be installed on the distribution system. The communications network allows for the backhaul of information from the intelligent electronic devices to centralized software and control applications. Simply collecting and displaying more sensing and measurement information won't provide the needed benefits. An integrated approach to the installation of field devices, software applications and historical data management will be needed. A distribution management system ("DMS") is the central software application that provides distribution supervisory control and data acquisition ("SCADA"), outage management and geographical information into a single operations view. By combining the information from all three of these systems into a single view an electrical distribution system model can be created for both real time applications and planning needs. The single view provides situational awareness of the distribution system that has not been possible in the past. It also creates a platform from which additional applications can be implemented to continue to provide value and new opportunities. The historical information also creates a new opportunity to drive value and decisions based on system performance and dynamic simulations.

With the development of multiple distribution micro grid feeders and DER systems, the challenge of resource dispatching will develop. A solution to dispatch across a fleet of resources of existing centralized generation, purchased power from the market and the intermittency of DER systems to customer demand will be required. The speed in which the resource pool will need to change and optimize for efficiency and cost will require the system to be automated. The distribution microgrid feeder concept is intended to help manage the distribution level intermittency but would need to be monitored and managed by the automated system for resource management. To manage such a large and dynamic system as outlined is a substantial challenge. This type of automated system is not currently available within the utility industry.

Energy Storage

The electric industry has always had an interest in the possibility of storing energy. Utilities have always strived to maintain a safe, reliable and cost effective electric grid. New challenges, such as the emergence of renewable generation has generated a greater interest in electric energy storage. The topic of Energy Storage Systems ("ESS") covers many different types of technology. Each technology has specific attributes and application that lead to using them based on individual system requirements for an identified need. The energy storage technologies are made up of systems such as pumped hydro, compressed air energy storage, various types of batteries, and flywheels.

Pumped Hydro-Power – This technology has been in use for nearly a century worldwide. Pumped hydro accounts for most of the installed storage capacity in the United States. Pumped hydro plants use lower cost off-peak electricity to pump water from a low-elevation reservoir to a higher reservoir. When the utility needs the electricity or when power prices are higher, the plant releases the water to flow through hydro turbines to generate power.

Typical pumped hydro facilities can store up to 10 or more hours of water for energy storage. Pumped hydro plants can absorb excess electricity produced during off-peak hours, provide frequency regulation, and help smooth the fluctuating output from other sources. Pumped hydro requires sites with suitable topography where reservoirs can be situated at different elevations and where sufficient water is available. Pumped hydro is economical only on a large (250-2,000 MW) scale, and construction can take several years to complete.

The round-trip efficiency of these systems usually exceeds 70 percent. Installation costs of these systems tend to be high due to siting requirements and obtaining environmental and construction permits presents additional challenges. Pumped hydro is a proven technology with high peak use coincidence. For UNSE, it is a less viable option due to limited available sites and water resources.

Compressed Air Energy Storage ("CAES") – A leading alternative for bulk storage is compressed air energy storage. CAES is a hybrid generation/storage technology in which electricity is used to inject air at high pressure into underground geologic formations. CAES can potentially offer shorter construction times, greater siting flexibility, lower capital costs, and lower cost per hour of storage than pumped hydro. A CAES plant uses electricity to compress air into a reservoir located either above or below ground. The compressed air is withdrawn, heated via combustion, and run through an expansion turbine to drive a generator. The dispatch typically will occur at high power prices but also when the utility needs the electricity,

CAES plants are in operation today— a 110-MW plant in Alabama and a 290-MW unit in Germany. Both plants compress air into underground caverns excavated from salt formations. The Alabama facility stores enough compressed air to generate power for 26 hours and has operated reliably since 1991.

CAES plants can use several types of air-storage reservoirs. In addition to salt caverns, underground storage options include depleted natural gas fields or other types of porous rock formations. EPRI studies show that more than half the United States has geology potentially suitable for CAES plant construction. Compressed air can also be stored in above-ground pressure vessels or pipelines. The latter could be located within right-of-ways along transmission lines. Responding rapidly to load fluctuations, CAES plants can perform ramping duty to smooth the intermittent output of renewable generation sources as well as provide spinning reserve and frequency regulation to improve overall grid operations.

Batteries – Several different types of large-scale rechargeable batteries can be used for ESS including lead acid, lithium ion, sodium sulfur (NaS), and redox flow batteries. Batteries can be located in distribution systems closer to end users to provide peak management solutions. An aggregation of large numbers of dispersed battery systems in smart-grid designs could even achieve near bulk-storage scales.

In addition, if plug-in hybrid electric vehicles become widespread, their onboard batteries could be used for ESS, by providing some of the supporting or "ancillary" services in the electricity market such as providing capacity, spinning reserve, or regulation services, or in some cases, by providing load-leveling or energy arbitrage services by recharging when demand is low to provide electricity during peak demand.

Flywheels – These rotating discs can be used for power quality applications since they can charge and discharge quickly and frequently. In a flywheel, energy is stored by using electricity to accelerate a rotating disc. To retrieve stored energy from the flywheel, the process is reversed with the motor acting as a generator powered by the braking of the rotating disc.

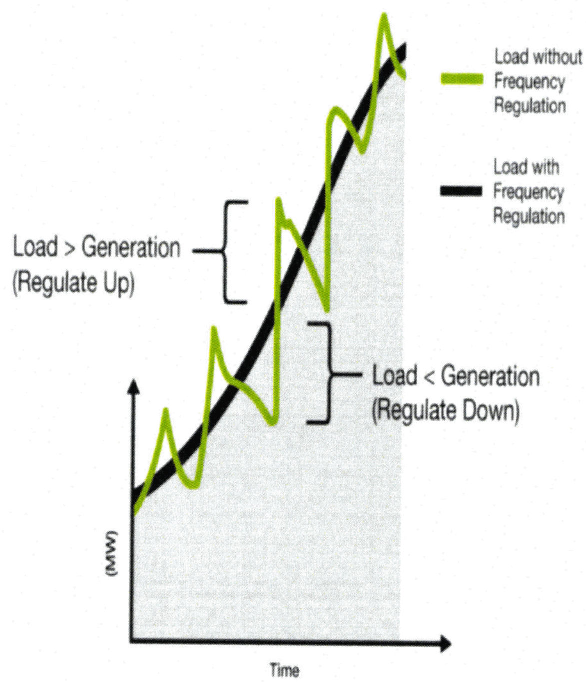
Flywheel systems are typically designed to maximize either power output or energy storage capacity, depending on the application. Low-speed steel rotor systems are usually designed for high power output, while high-speed composite rotor systems can be designed to provide high energy storage. A major advantage of flywheels is their high cycle life—more than 100,000 full charge/discharge cycles.

Scale-power versions of the system, a 100 kW version using modified existing flywheels which was a proof of concept on approximately a 1/10th power scale, performed successfully in demonstrations for the New York State Energy Research and Development Authority and the California Energy Commission.

Energy Storage Applicability

Although the list of energy storage technologies discussed above is not all-inclusive, it begins to illustrate the point that not every type of storage is suitable for every type of application. Typical use applications for energy storage technologies may include:

- Energy Management – Batteries can be used to provide demand reduction benefits at the utility, commercial and residential level. Batteries can be ideal or designed to replace traditional gas peaking resources. They can also be used as short-term replacement during emergency conditions.
- Load and Resource Integration – Energy storage systems can be designed to smooth the intermittency characteristics of specific loads and/or solar systems during cloud migrations.
- Ancillary Services – Flywheels and batteries have the potential to balance power and maintain frequency, voltage and power quality at specified tolerance bands.
- Grid Stabilization – Pumped Hydro, CAES and various batteries can improve transmission grid performance as well as assist with renewable generation stabilization.



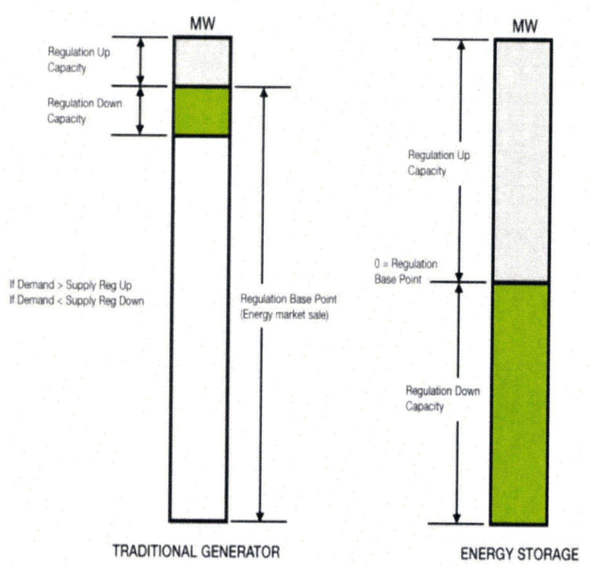
Because of the different use case potentials the technologies can be implemented in a portfolio strategy. There are four challenges related to the widespread deployment of energy storage:

- Cost Competitive Energy Storage Technologies (including manufacturing and grid integration)
- Validated Reliability & Safety
- Equitable Regulatory Environment
- Industry Acceptance

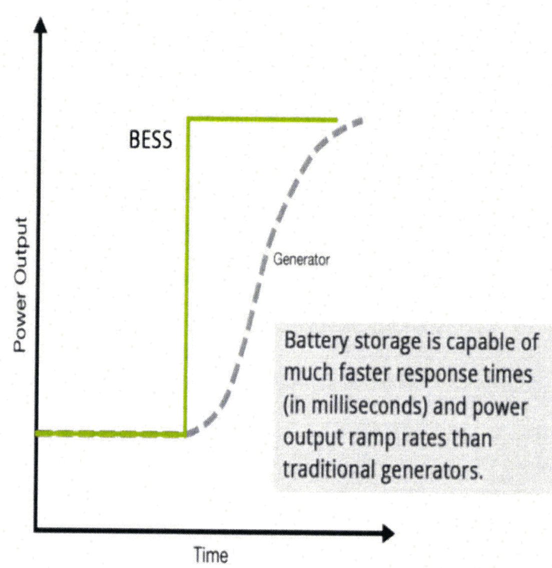
UNSE shows the need to develop a portfolio of future storage technologies that will support long-term grid reliability. The need for future storage technologies is focused on supporting the need for quick response time ancillary services. These services are listed below:

- Load Following/Ramping
- Regulation
- Voltage Support
- Power Quality
- Frequency Response

The Role of Energy Storage



The Value Proposition



The following is a narrative from Lazard's first version of its Levelized Cost of Energy Analysis[11]. Lazard's first version of its Levelized Cost of Storage Analysis (LCOE 1.0) provides an independent, in-depth study that compares the costs of energy storage technologies for particular applications.[12] The study's purpose is to compare the cost-effectiveness of each technology on an "apples to apples" basis within applications, and to compare each application to conventional alternatives.[13] Key findings of LCOS 1.0 include: 1) select energy storage technologies are cost-competitive with certain conventional alternatives in a number of specialized power grid uses and 2) industry participants expect costs to decrease significantly in the next five years, driven by increasing use of renewable energy generation, governmental and regulatory requirements and the needs of an aging and changing power grid.

LAZARD'S STORAGE ANALYSIS: KEY FINDINGS

Cost Competitive Storage Technologies

Select energy storage technologies are cost-competitive with certain conventional alternatives in a number of specialized power grid uses, but none are cost-competitive yet for the transformational scenarios envisioned by renewable energy advocates.

Although energy storage technology has created a great deal of excitement regarding transformational scenarios such as consumers and businesses "going off the grid" or the conversion of renewable energy sources to baseload generation, it is not currently cost competitive in most applications. However, some uses of select energy storage technologies are currently attractive relative to conventional alternatives; these uses relate primarily to strengthening the power grid (e.g., frequency regulation, transmission investment deferral).

Today, energy storage appears most economically viable compared to conventional alternatives in use cases that require relatively greater power capacity and flexibility as opposed to energy density or duration. These use cases include frequency regulation and—to a lesser degree—transmission and distribution investment deferral, demand charge management and microgrid applications. This finding illustrates the relative expense of incremental system duration as opposed to system power. Put simply, "battery life" is more difficult and costly to increase than "battery size." This is likely why the potentially transformational use cases such as full grid defection are not currently economically attractive—they require relatively greater energy density and duration, as opposed to power capacity

LCOS 1.0 finds a wide variation in energy storage costs, even within use cases. This dispersion of costs reflects the immaturity of the energy storage industry in the context of power grid applications. There is relatively limited competition and a mix of "experimental" and more commercially mature technologies competing at the use case level. Further, seemingly as a result of relatively limited competition and lack of industry transparency, some vendors appear willing to participate in use cases to which their technology is not well suited

[11] Lazard is a preeminent financial advisory and asset management firm. More information can be found at https://www.lazard.com

[12] Lazard conducted the Levelized Cost of Storage analysis with support from Enovation Partners, an leading energy consulting firm.

[13] Energy storage has a variety of uses with very different requirements, ranging from large-scale, power grid-oriented uses to small-scale, consumer-oriented uses. The LCOS analysis identifies 10 "use cases," and assigns detailed operational parameters to each. This methodology enables meaningful comparisons of storage technologies within use cases, as well as against the appropriate conventional alternatives to storage in each use case.

Future Energy Storage Cost Decreases

Industry participants expect costs to decrease significantly in the next five years, driven by increasing use of renewable energy generation, government policies promoting energy storage and pressuring certain conventional technologies, and the needs of an aging and changing power grid.

Industry participants expect increased demand for energy storage to result in enhanced manufacturing scale and ability, creating economies of scale that drive cost declines and establish a virtuous cycle in which energy storage cost declines facilitate wider deployment of renewable energy technology, creating more demand for storage and spurring further innovation in storage technology

Cost declines projected by Industry participants vary widely between storage technologies— lithium is expected to experience the greatest five year battery capital cost decline (~50%), while flow batteries and lead are expected to experience five year battery capital cost declines of ~40% and ~25%, respectively. Lead is expected to experience 5% five year cost decline, likely reflecting the fact that it is not currently commercially deployed (and, possibly, the optimism of its vendor's' current quotes)

The majority of near- to intermediate- cost declines are expected to occur as a result of manufacturing and engineering improvements in batteries, rather than in balance of system costs (e.g., power control systems or installation). Therefore, use case and technology combinations that are primarily battery-oriented and involve relatively smaller balance of system costs are likely to experience more rapid levelized cost declines. As a result, some of the most "expensive" use cases today are most "levered" to rapidly decreasing battery capital costs. If industry projections materialize, some energy storage technologies may be positioned to displace a significant portion of future gas-fired generation capacity, in particular as a replacement for peaking gas turbine facilities, enabling further integration of renewable generation

See the full report at https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

Chapter 5

OTHER RESOURCE PLANNING TOPICS

Energy Imbalance Market

Energy imbalance on an electrical grid occurs when there is a difference between real-time demand, or load consumption, and generation that is prescheduled. Prior to the emergence of renewable energy technology on the grid, balancing occurred to correct operating limits within 30 minutes. Flows are often managed manually by system operators and typically bilaterally between power suppliers. The intermittent characteristics of wind and solar resources have raised concerns about how system operators will maintain balance between electric generation and demand in smaller than thirty minute increments. Energy Imbalance Markets ("EIMs") create a much shorter window market opportunity for balancing loads and resources. An EIM can aggregate the variability of resources across much larger footprints than current balancing authorities and across balancing authority areas. The sub hourly clearing, in some cases down to 5 minutes potentially provides economic advantage to participants in the market. EIMs propose to moderate, automate and effectively expand system-wide dispatch which can help with the variability and intermittency of renewable resources. EIMs boast to create significant reliability and renewable integration benefits by sharing resource reserves across much larger footprints.

CAISO – EIM

On November 1, 2014, the CAISO welcomed PacifiCorp into the western EIM. Nevada-based NV Energy began active participation in the EIM on December 1, 2015. This voluntary market service is available to other grids in the West. Several Western utilities have committed to join the EIM. Meanwhile, work is underway for Puget Sound Energy in Washington and Arizona Public Service to enter the real-time market in October 2016. In the fall of 2015, Portland General Electric and Idaho Power each announced their intentions to pursue EIM participation.

Participants in the EIM expect to realize at least three benefits:

- Produce economic savings to customers through lower production costs
- Improve visibility and situational awareness for system operations in the Western Interconnection
- Improve integration of renewable resources

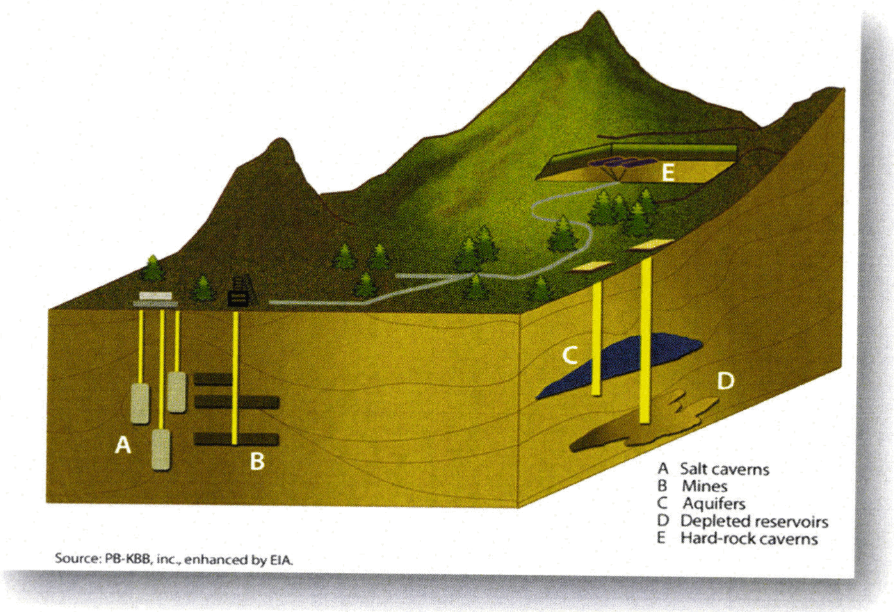
TEP has contracted with the energy consulting firm E3 to perform a study to determine the economic benefits of TEP participating in the energy imbalance market. E3 will evaluate EIM benefits to TEP based on a set of study scenarios defined through discussions with TEP to reflect TEP system information, including loads, resources, and potential transmission constraints for access to markets for real-time transactions. The project analysis began in February 2016 and is expected to be completed by the end of June, 2016. TEP will then evaluate the relevant costs and benefits of joining the western EIM. UNSE is within the TEP balancing authority and therefore will also make a determination to participate based on the TEP analysis and results.

Natural Gas Storage

Natural gas is a fuel source that produces less carbon dioxide than coal for a given unit of energy generation. Natural gas-powered electric generation can also be more responsive and supportive of the variability and intermittency of renewable generation. Natural gas usage has historically undergone seasonal fluctuations with higher consumption during the winter months due to residential and commercial heating. The displacement of coal and the emergence of renewable generation will likely shift gas demand increases to the summer months. As utilities potentially began to lean more toward natural gas-powered electric generation, an ensuing issue or concern is the ability of supply and deliverability to meet increased demand. The availability of natural gas storage helps alleviate some concern.

Natural gas is pivotal in maintaining a reliable electric grid. Natural gas storage provides a reliability backstop to a multitude of disruptions that may impact the delivery of natural gas. Storage helps to level the balance of production, which is relatively constant, and the seasonally driven demand or consumption. Gas can be injected into storage while demand is low and released for consumption while demand is high or while there are disruptions in supply. Much like water stored behind dams allows for timely irrigation of seasonal crops and for Natural gas storage is typically stored underground and primarily in three different formations; depleted oil and/or gas reservoirs, aquifers and salt cavern formations.

Figure 8 – Natural Gas Storage Types



Source: EIA Energy Information Administration

Depleted Reservoirs – The reservoirs result from the void remaining after gas or oil is recovered. Depleted reservoirs are more widely available and the most utilized. This form of storage is the most common for natural gas storage. Their availability, of course, is dependent on the location of existing wells and pipeline infrastructure. To maintain adequate withdrawal pressure, up to 50% of the stored gas capacity becomes unrecoverable cushion gas, this depends on how much native gas remains in the reservoir. Injection and withdrawal rates are also dependent on the geological characteristics.

Aquifers – The use of aquifers has been more prevalent in the Midwestern United States. In the case of depleted gas and aquifer storage reservoirs, the effectiveness of storage is primarily dependent on the geological conditions. The rock formation porosity, permeability, and retention capability are important. A suitable aquifer is one that is overlaid with impermeable cap layer. Unlike depleted reservoirs, where expensive infrastructure was installed during the exploration and extraction of oil and gas, aquifers require extensive capital investment. Since aquifers are naturally full of water, in some instances powerful injection equipment must be used, to allow sufficient injection pressure to push down the resident water and replace it with natural gas. Aquifers typically operate with one withdrawal period per year; this is because of slow fill to push water back.

Salt Caverns – The best opportunity for natural gas storage in Arizona and in the Southwest might be in salt caverns. Salt caverns allow for high withdrawal and injection rates of natural gas. This makes salt caverns ideal to meet demand increases or to operate as emergency back-up systems. Salt caverns are created through a process called solution mining; fresh water is blasted into salt formations and the mixture is flushed to the surface creating a chamber. The chambers are structurally strong and extremely air tight. While cushion gas is still required at a 20% to 30% level, it is less than required for depleted reservoirs.

Integration of Renewables

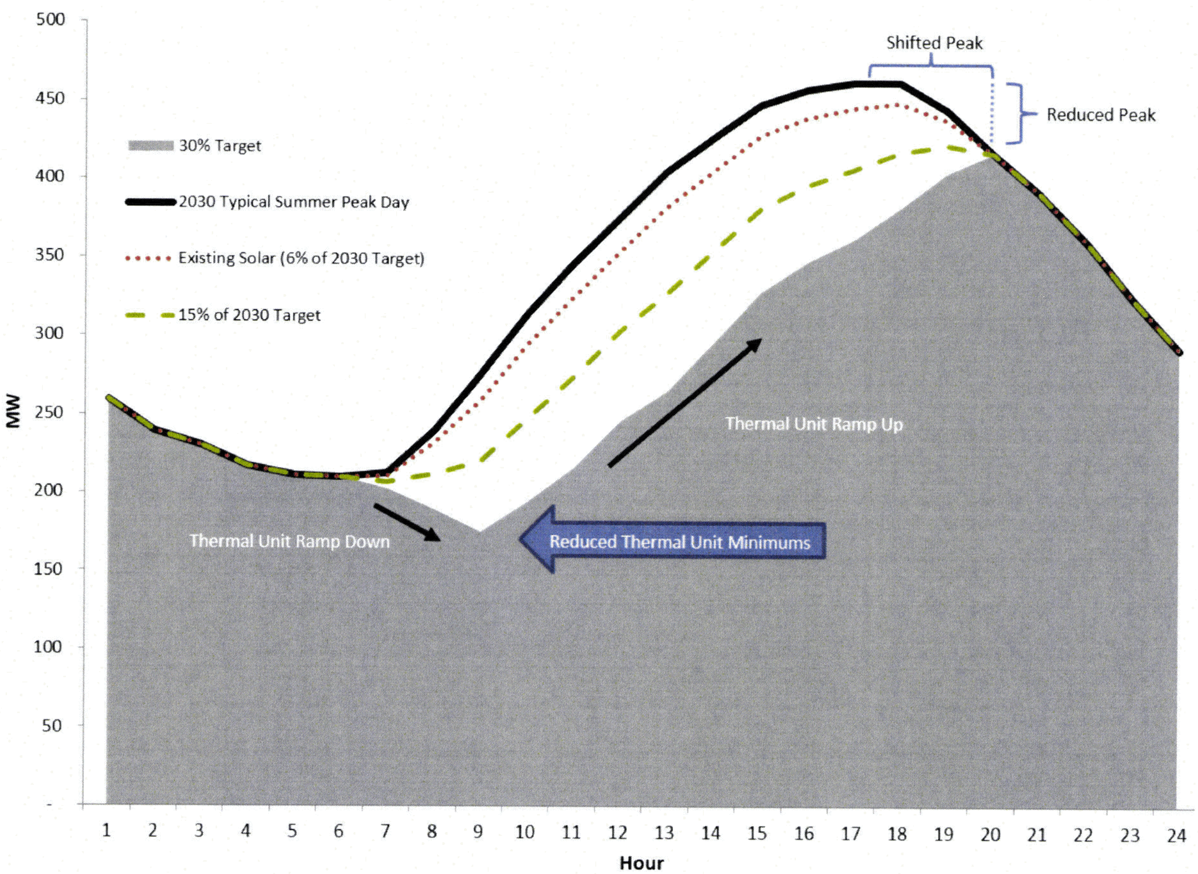
The value and cost of renewable solar PV is estimated to change with increased penetration. To determine the value of solar PV, it's imperative to understand its relationship to consumer load. In the case of Distributed Generation, most renewable solar is sited 'behind the meter' or on customer facilities. The relationship of a DG solar installation at a residential site is assumed to be different than an installation at a commercial site. We can assume that residential peak load occurs soon after consumers arrive home from work. Commercial peak tends to occur during the early to mid-afternoon work hours. This is an important distinction in this discussion because the costs and value vary due between the multiple customer types. However for this discussion we will refer only to the impact on the system in its entirety and for solar as a whole.

Historically, electric utilities with predominant air conditioning load set a peak demand between 4:00 PM to 5:00 PM on a summer day. Solar PV can help reduce this peak but not at the full potential of its solar output. Fixed array solar peak production is typically at 12:00 to 1:00 PM, while single-axis tracking systems can expand its potential to coincide more with the retail peak demand. UNSE's current renewable portfolio (to include DG and wind) is at approximately 5% of 2030 retail energy projection.

Chart 10 below demonstrates that the existing penetration of solar already has an observable reduction to retail peak demand. Closer examination also reveals that the net peak is beginning to shift to the right. The reduction to the peak in 2030 from existing solar is approximately 4%. While a reduction to retail peak is observed, only 40% of the solar installed capacity contributes to that reduction.

UNSE is committed to meeting the 15% RES by 2025. By maintaining that commitment through 2030, the solar component of the renewable portfolio reduces peak by another 6%. Though there is an obvious reduction in peak, the time the peak is set is shifting closer to the last diurnal hour of a typical clear-sky summer day (7:00 to 8:00 PM). It is significant then to note that though we introduce a 30% renewable target with a high penetration of solar, the reduction to the new shifted (7:00 PM) peak attributed to solar is beginning to diminish. We observe a 1% reduction to retail peak but a significant drop (from 40% to 6%) to peak contribution from the incremental solar capacity additions. As retail load grows, solar PV (without storage capabilities) cannot contribute to the reduction of peak demand beyond 7:00 PM; regardless of its penetration.

Chart 10 – Impact of Increased Solar Production (Duck Curve)



While it can be argued that solar may contribute to reduced losses, to apportioned capacity reductions (generation and transmission), and carbon emission reductions among other benefits, we note from the chart above that other challenges arise. As the sun is rising, electric load stabilizes and begins an ascent toward the peak. Increased penetration of solar creates a rapid net drop in load and UNSE must have generators that are capable of ramping down at a fast rate. Most base-load units such as coal and gas-steam are challenged to respond to this ramp down and subsequent ramp up. It is at this point that the net reduction in load can create the need for rapid responding generators to regulate the initial steep decline in load followed by an immediate rise. From a resource planning context, with the increasing penetration of solar systems, we must take into consideration the right combination of resources to respond to the variability and intermittency of renewable systems. A portfolio with a high penetration of solar and other renewables may necessitate the installation of reciprocating internal combustion engines and/or storage in the form of batteries or gas.

Natural Gas Reserves

Proven reserves of natural gas are estimated quantities that analyses of geological and engineering data have demonstrated to be economically recoverable from known reservoirs in the future. According to EIA, major advances in natural gas exploration and technology has increased reserves in 2014 to 388.8 trillion cubic feet (Tcf) from 354.0 Tcf reserves in 2013.

Table 9 – U.S Proved Reserves and Reserve Changes (2013 to 2014)

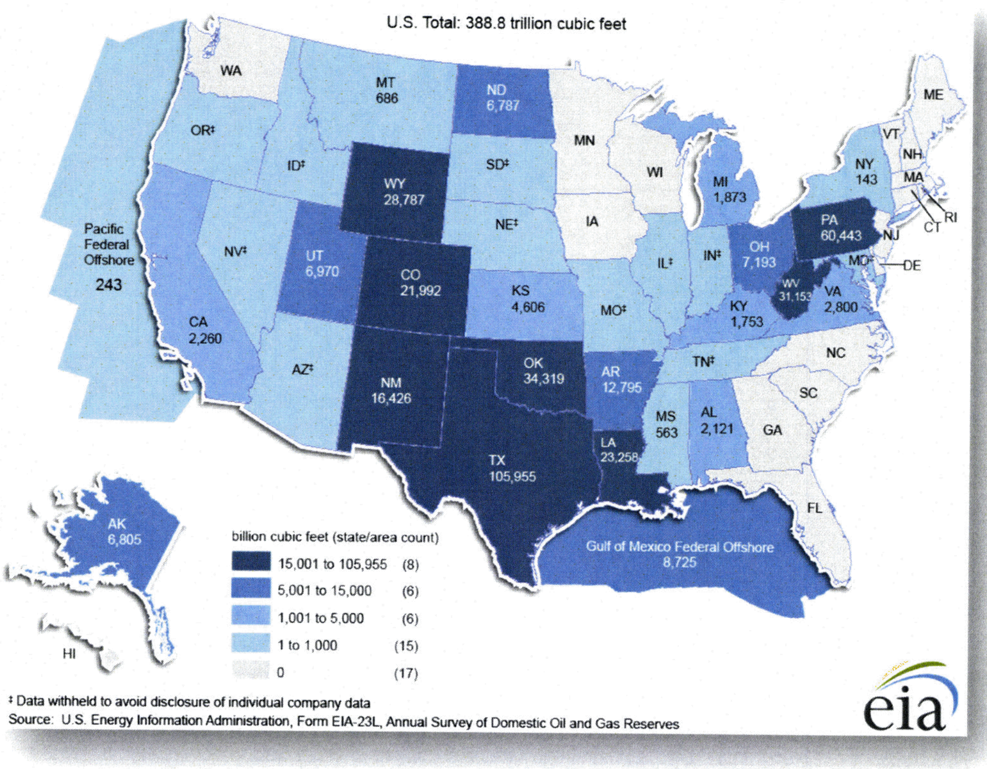
	Wet Natural Gas -Tcf
U.S. proven reserves at December 31, 2013	**354.0**
Total discoveries	50.5
Net revisions	1.0
Net Adjustments, Sales, Acquisitions	11.5
Production	-28.1
Net additions to U.S. proved reserves	**34.8**
U.S. proven reserves at December 31, 2014	**388.8**
Percent change in U.S. proved reserves	**9.8%**

Notes: Total natural gas includes natural gas plant liquids. Columns may not add to total because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-23L, Annual Survey of Domestic Oil and Gas Reserves

Proven reserves are added each year with successful exploratory wells and as more is learned about fields where current wells are producing. The application of new technologies can convert previously uneconomic natural gas resources into proven reserves. U.S. proven reserves of natural gas have increased every year since 1999. Figure 10 illustrates the distribution of the reserves by state and offshore area.

Figure 10 – EIA Natural Gas Proven Reserves by State/Area (2014)



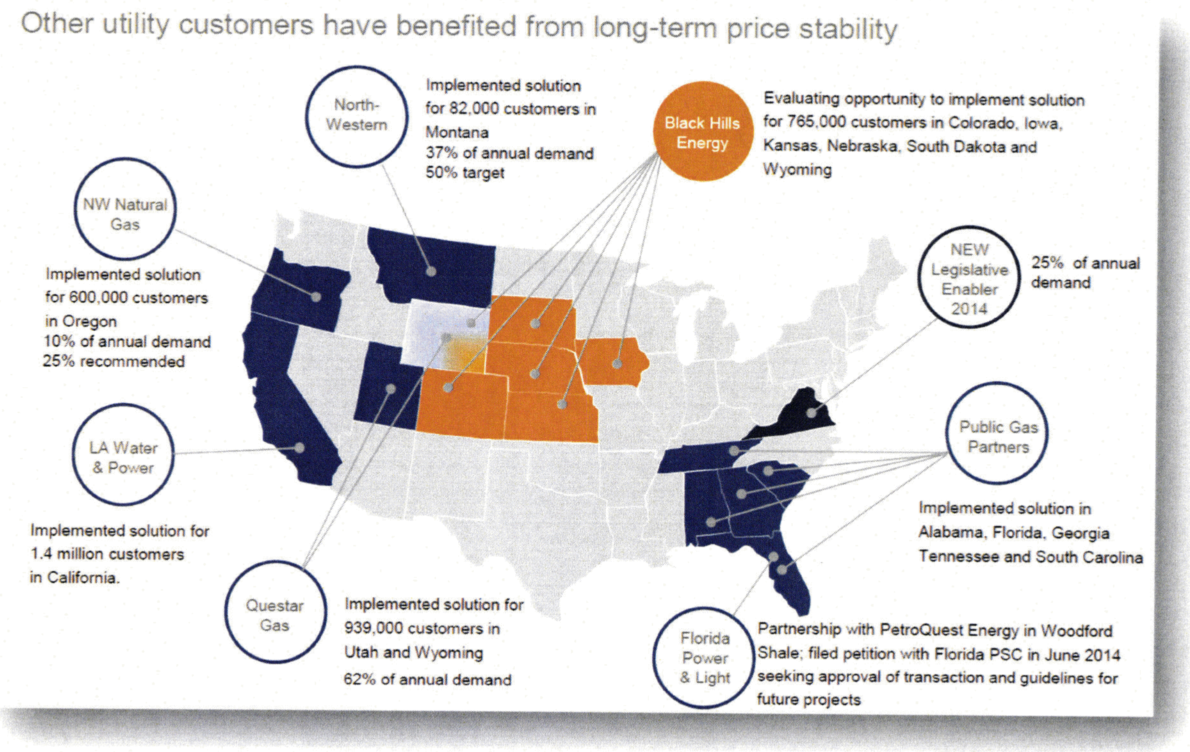
Utility Ownership in Natural Gas Reserves

As utilities place more reliance on cleaner more efficient natural gas resources, UNSE has been researching new ways to lock in long-term fuel price stability for natural gas. One potential solution being explored by a number of gas and electric utilities is the investment and ownership in physical natural gas reserves.

Over the last few years, a number of utilities have partnered with third-party natural gas producers to develop partnerships to acquire and develop natural gas reserves. These partnerships were formed as an alternative approach to existing financial hedging practices and were seen as a way for companies to develop a long-term physical hedge for its expanding gas generation fleet.

Production of oil and associated natural gas has grown substantially over the last several years leading to a supply surplus that has depressed natural gas prices to the lowest they have been in twenty years. As a result, this environment creates opportunities for utilities and other large gas purchasers to acquire natural gas reserves at historic lows. The figure below highlights a number of companies that have successfully developed partnerships around natural gas reserve ownership.

Figure 11 - Overview of Recent Utility - Third Party Gas Reserve Projects



Regional coal diversification strategies and the shift to rely on more natural gas will encourage utilities to secure natural gas reserves. The Company plans to explore how it might pursue similar partnerships with regional gas and electric utilities in an effort secure long-term natural gas price stability for its customers.

Chapter 6

FUTURE RESOURCE OPTIONS AND MARKET ASSUMPTIONS

In considering future resources, the resource planning team evaluates a mix of renewable and conventional generation technologies. This mix of technologies included both commercially available resources and promising new technologies that are likely to become technically viable in the near future. The IRP process takes a high-level approach and focuses on evaluating resource technologies rather than specific projects. This approach allows the resource planning team to develop a wide-range of scenarios and contingencies that result in a resource acquisition strategy that contemplates future uncertainties.

Assumptions on cost and operating characteristics are typically gathered from several data sources. Below is a list of resources that UNSE relies on to compile capital cost assumptions for thermal and renewable resources:

- U.S. Energy Information Administration - https://www.eia.gov/forecasts/aeo/electricity_generation.cfm
- Western Electricity Coordinating Council (as recommended by E3) - https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf
- Black & Veatch - http://bv.com/docs/reports-studies/nrel-cost-report.pdf
- National Renewable Energy Laboratory - http://www.nrel.gov/analysis/re_futures/index.html
- Lazard - https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf; https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf

UNSE relies on a number of third-party data sources and consultants to derive assumption in its on-going planning practices. In addition, information gathered through our competitive bidding process or request for proposal process can be used to put both self-build resources and market-based purchased power agreements on a comparative basis.

Generation Resources – Matrix of Applications

Table 6 provides a brief overview of the types of generating resources that will be included and evaluated in the resource planning process for the 2017 final IRP. For each technology type a brief summary of potential risks and benefits are listed. In addition, attributes such as costs, siting requirements, dispatchability, transmission requirements and environmental potential are summarized.

Table 6 - Resource Matrix

Category	Type	Zero or Low Carbon Potential	State of Technology	Local Area Option	Intermittent	Peaking	Load Following	Base Load
Energy Efficiency	Energy Efficiency	Yes	Mature	Yes				
Demand Response	Direct Load Control	Yes	Mature	Yes		✓		
Renewables	Wind	Yes	Mature		✓			
	Solar PV	Yes	Mature	Yes	✓	✓		
	Solar Thermal	Yes	Mature		✓	✓	Storage (1)	
Conventional	Reciprocating Engines		Mature			✓	✓	✓
	Combustion Turbines		Mature	Yes		✓	✓	
	Combined Cycle (NGCC)		Mature	Yes		✓	✓	✓
	Small Modular Nuclear (SMR)	Yes	Emerging					✓

(1) Natural Gas hybridization or thermal storage could allow resource to be dispatched to meet utility peak load requirements.

Comparison of Resources

Generation planning and resource analysis can be performed by using a wide spectrum of tools and methodologies. Prior to running detailed simulation models for the 2017 Final IRP, the UNSE resource planning team will combine the source information and settle on the cost parameters for the varying technologies. Table 7 and Table 8 shown below demonstrate a comparison of capital cost estimates, used by UNSE in the 2012 and 2014 IRPs versus costs published by Third-Party Sources, for thermal and renewable resources respectively. The tables demonstrate the varying range of costs, even within each technology. In the 2017 Final IRP, the resource planning group will incorporate the input from third-party sources, stakeholders and other data sources to derive a reasonable set of cost inputs (construction, EHV/interconnection, construction to include ITC, fixed O&M, variable O&M, and fuel costs).

Table 7 – Capital Cost for Thermal Resources

Plant Construction Costs	Units	Small Aeroderivative Combustion Turbine	Small Frame Combustion Turbine	Natural Gas Reciprocating Engines	Small Modular Reactor (SMR)	Natural Gas Combined Cycle (NGCC)
2012 IRP	2012 $/kW	$1,156	$779	-	-	$1,320
2014 IRP	2014 $/kW	$1,062	$808	-	-	$1,367
Third Party Source	2014 $/kW	$1,150	$825	$1,300	-	$1,125
Third Party Source	2016 $/kW	$800 - $1,000	$800 - $1,000	$1,150	-	$1,000 - $1,300
Preliminary IRP Estimate	2016 $/kW	$1,250	$800	$1,200	$6,400	$1,300

Table 8 – Capital Cost for Renewable Resources

Plant Construction Costs	Units	Solar Thermal 6 Hour Storage (100 MW)	Solar Fixed PV (20 MW)	Solar Single Axis Tracking (20 MW)	Wind Resources (50 MW)
2012 IRP	2012 $/kW	$5,650	$2,350	$2,549	$2,400
2014 IRP	2014 $/kW	$7,144	$1,993	$2,290	$2,278
Third Party Source	2014 $/kW	$7,100	$3,325	$3,800	$2,000
Third Party Source	2016 $/kW	$10,000 - $10,300	$1,400 - $1,500	$1,600 - $1,750	$1,250 - $1,700
Preliminary IRP Estimate	2016 $/kW	$10,000	$1,500	$1,600	$1,450

LEVELIZED COST COMPARISONS

The calculation of the levelized cost of electricity ("LCOE") provides a common measure to compare the cost of energy across different demand and supply-side technologies. The LCOE takes into account the installed system price and associated costs such as capital, operation and maintenance, fuel, transmission, tax incentives and converts them into a common cost metric of dollars per megawatt hour. The calculation for the LCOE is the net present value of total costs of the project divided by the quantity of energy produced over the system life.

Because intermittent technologies such as renewables do not provide the same contribution to system reliability as technologies that are operator controlled and dispatched, they require additional system investment for system regulation and backup capacity. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change. Further resource utilization is dependent on many factors; the portfolio mix, regional market prices, customer demand and must-run requirements are some considerations outside of LCOE.

The LCOE projection contains many factors that will vary between now and when the final IRP is filed on April 1, 2017. As such, UNSE will derive the levelized costs at the time that the capital costs and other inputs are prepared for final analysis.

RENEWABLE TECHNOLOGIES – COST DETAILS

Table 9 includes the renewable technology costs for the 2016 Preliminary Integrated Resource Plan.

Table 9 - Renewable Resource Cost Assumptions

Plant Construction Costs	Units	Solar Thermal 6 Hour Storage (100 MW)	Solar Fixed PV (20 MW)	Solar Single Axis Tracking (20 MW)	Wind Resources (50 MW)
Project Lead Time	Years	4	2	2	2
Installation Years	First Year Available	2020	2018	2018	2018
Peak Capacity	MW	100	20	100	50
Plant Construction Cost	2016 $/kW	$9,800	$1,450	$1,550	$1,250
EHV/Interconnection Cost	2016 $/kW	200	50	50	200
Total Construction Cost	2016 $/kW	$10,000	$1,500	$1,600	$1,450
Operating Characteristics					
Fixed O&M	2016 $/kW	$80.00	$13.00	$10.00	$40.00
Typical Capacity Factor	Annual %	50%	29%	25%	33%
Expected Annual Output	GWh	438	110	127	145
Net Coincident Peak	NCP%	85%	33%	51%	13%
Water Usage	Gal/MWh	800	0	0	0
ITC	Percent	30%	30%	30%	-
PTC	$/MWh	-	-	-	$23.00
Levelized Cost of Energy	$/MWh	$161	$54	$70	$49

CONVENTIONAL TECHNOLOGIES – COST DETAILS

Table 10 includes the conventional resource cost assumptions for the 2016 Preliminary Integrated Resource Plan.

Table 10 - Conventional Resource Cost Assumptions

Plant Construction Costs	Units	Small Aeroderivative Combustion Turbine	Small Frame Combustion Turbine	Natural Gas Reciprocating Engines	Small Modular Reactor (SMR)	Natural Gas Combined Cycle (NGCC)
Project Lead Time	Years	4	4	2	12	4
Installation Years	First Year Available	2020	2020	2018	2028	2020
Peak Capacity , MW	MW	45	75	2	300	550
Plant Construction Cost	2016 $/kW	$1,200	$770	$1,070	$6,000	$1,135
EHV/Interconnection Cost	2016 $/kW	50	30	30	400	165
Total Construction Cost	2016 $/kW	$1,250	$800	$1,200	$6,400	$1,300
Operating Characteristics						
Fixed O&M	2016 $/kW	$12.50	$13.25	$17.50	$29.30	$16.50
Variable O&M	2016 $/kW	$3.50	$3.75	$12.50	$5.00	$2.00
Gas Transportation	2016 $/kW	$16.80	$16.80	$16.80	-	$16.80
Annual Heat Rate	Btu/kWh	9,800	10,500	9,000	10,400	7,200
Typical Capacity Factor	Annual %	15%	8%	45%	85%	50%
Expected Annual Output	GWh	59	53	8	2,234	2,409
Fuel Source	Fuel Source	Natural Gas	Natural Gas	Natural Gas	Uranium	Natural Gas
Unit Fuel Cost	$/mmBtu	$5.67	$5.67	$5.67	$0.90	$5.67
Net Coincident Peak	NCP%	100%	100%	100%	100%	100%
Water Usage	Gal/MWh	150	150	50	800	350
Levelized Cost of Energy	$/MWh	$247	$306	$135	$145	$103

The following is a narrative from Lazard's ninth version of its Levelized Cost of Energy Analysis[14]. Lazard's ninth version of its Levelized Cost of Energy Analysis (LCOE 9.0) analysis provides an independent, in-depth study of alternative energy costs compared to conventional generation technologies. The central findings of the study are: 1) the cost competitiveness and continued price declines of certain alternative energy technologies; 2) the necessity of investing in diverse generation resources for integrated electric systems for the foreseeable future; and 3) the importance of rational and transparent policies that support a modern and increasingly clean energy economy.

Lazard - https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

LAZARD's LEVELIZED COST OF ENERGY ANALYSIS: KEY FINDINGS

Cost Competiveness of Alternative Energy Technologies

Certain alternative energy technologies (e.g., wind and utility-scale solar) continue to become more cost-competitive with conventional generation technologies in some applications, despite large decreases in the cost of natural gas. Lazard's analysis does not take into account potential social and environmental externalities (e.g., the social costs of distributed generation, environmental consequences of conventional generation, etc.) or reliability- or intermittency-related considerations (e.g., transmission system or back-up generation costs associated with certain alternative energy technologies)

Despite a sharp drop in the price of natural gas, the cost of all forms of utility-scale solar photovoltaic and utility-scale wind technologies continue to remain competitive with conventional generation technologies as illustrated by the proliferation of successful bids by renewable energy providers in open power procurement processes.

Currently, rooftop solar PV is not cost competitive without significant subsidies, due, in part, to the small-scale nature and added complexity of rooftop installation. However, the LCOE of rooftop solar PV is expected to decline in coming years, partially as a result of more efficient installation techniques, lower costs of capital and improved supply chains. Importantly, Lazard excludes from their analysis the value associated with certain uses of rooftop solar PV by sophisticated commercial and industrial users (e.g., demand charge management, etc.), which appears increasingly compelling to certain large energy customers.

Community based solar projects, in which members of a single community (e.g., housing subdivisions, rental buildings, industrial parks, etc.) own divided interests in small-scale ground-mounted solar PV facilities, is becoming more widespread and compelling in certain areas. These projects, which allow participants to receive credits against their electric bills either by state statute or negotiated agreements between the project sponsors and local utilities, provide solar energy access to consumers without the economic means or property rights to install rooftop solar PV. However, while community solar projects benefit from increased scale and decreased installation complexity as compared to rooftop solar PV, most community scale projects are relatively small compared to utility-scale PV projects, and are therefore more expensive compared to utility-scale solar PV.

The pronounced cost decrease in certain intermittent alternative energy technologies, combined with the needs of an aging and changing power grid in the U.S., has significantly increased demand for energy storage technologies to fulfill a variety of electric system needs (e.g., frequency regulation, transmission/substation

[14] Lazard is a preeminent financial advisory and asset management firm. More information can be found at https://www.lazard.com

investment deferral, demand charge shaving, etc.). Industry participants expect this increased demand to drive significant cost declines in energy storage technologies over the next five years. Increased availability of lower-cost energy storage will likely facilitate greater deployment of certain alternative energy technologies.

Energy efficiency remains an important, cost-effective form of alternative energy. However, costs for various energy efficiency initiatives vary widely and may fail to account for the opportunity costs of foregone consumption.

Very large-scale conventional and renewable generation projects (e.g., IGCC, nuclear, solar thermal, etc.) continue to face a number of challenges, including significant cost contingencies, high absolute costs, competition from relatively cheap natural gas in some geographies, operating difficulties and policy uncertainty.

The Need for Diverse Generation Portfolios

Despite the increasing cost-competiveness of certain alternative energy technologies, future resource planning efforts will require diverse generation fleets to meet baseload generation needs for the foreseeable future. The optimal solution for many utilities is to use alternative energy technologies as a complement to existing conventional generation technologies. Overall, the U.S. will continue to benefit from a balanced generation mix, including a combination of alternative energy and conventional generation technologies.

While some alternative energy technologies have achieved notional "grid parity" under certain conditions (e.g., best-in-class wind/solar resources), such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of conventional generation, etc.), or reliability- related considerations.

The Importance of Rational and Transparent Energy Policies

The rapidly changing dynamics of energy costs have important ramifications for the industry, policymakers and the public. In the U.S., a coordinated federal and state energy policy, grounded in cost analysis, could enable smarter energy development, leading to sustainable energy independence, a cleaner environment and a stronger economic base.

Alternative energy costs have decreased dramatically in the past six years, driven in significant part by federal subsidies and related financing tools, and the resulting economies of scale in manufacturing and installation. Many of these subsidies have already or are expected to step down or expire for selected alternative energy technologies. A key question for industry participants will be whether these technologies can continue their cost declines and achieve wider adoption without the benefit of subsidies

The public narrative surrounding alternative energy technologies remains focused to a large degree on rooftop solar PV, notwithstanding its significantly higher LCOE relative to utility- scale solar PV and wind, and its potentially adverse social effects in the context of existing net metering regimes (e.g., high-income homeowners benefiting from such regimes while still relying on the broader power grid, and related cost transfers to the relatively less affluent). This focus, combined with the availability of government incentives for rooftop solar, distorts intelligent system-wide integrated resource planning and policy.

See the full report at https://www.lazard.com/media/2390/lazards-levelized-cost-of-energy-analysis-90.pdf

Renewable Electricity Production Tax Credit ("PTC")

The federal renewable electricity production tax credit is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities.

In December 2015, the Consolidated Appropriations Act, 2016 extended the expiration date for the production tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016. The Act extended the tax credit for other eligible renewable energy technologies commencing construction through December 31, 2016. The Act applies retroactively to January 1, 2015.

The tax credit amount is adjusted for inflation by multiplying the tax credit amount by the inflation adjustment factor for the calendar year in which the sale occurs, rounded to the nearest 0.1 cents. The Internal Revenue Service ("IRS") publishes the inflation adjustment factor no later than April 1 each year in the Federal Registrar. For 2015, the inflation adjustment factor used by the IRS is 1.5336.

Applying the inflation-adjustment factor for the 2014 calendar year, as published in the IRS Notice 2015-20, the production tax credit amount is as follows:

- $0.023/kWh for wind, closed-loop biomass, and geothermal energy resources
- $0.012/kWh for open-loop biomass, landfill gas, municipal solid waste, qualified hydroelectric, and marine and hydrokinetic energy resources.

The tax credit is phased down for wind facilities and expires for other technologies commencing construction after December 31, 2016. The phase-down for wind facilities is described as a percentage reduction in the tax credit amount described above:

Table 11 – Production Tax Credit Phase Down

Construction Year (1)	PTC Reduction
2017	PTC amount is reduced by 20%
2018	PTC amount is reduced by 40%
2019	PTC amount is reduced by 60%

(1) For wind facilities commencing construction in year.

Note that the exact amount of the production tax credit for the tax years 2017-2019 will depend on the inflation-adjustment factor used by the IRS in the respective tax years. The duration of the credit is 10 years after the date the facility is placed in service.

See http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc for more details.

Energy Investment Tax Credit ("ITC")

The Consolidated Appropriations Act, signed in December 2015, included several amendments to the federal Business Energy Investment Tax Credit which apply to solar technologies and other PTC eligible technologies. Notably, the expiration date for these technologies was extended, with a gradual step down of the credits between 2019 and 2022.

The ITC has been amended a number of times, most recently in December 2015. The table below shows the value of the investment tax credit for each technology by year. The expiration date for solar technologies and wind is based on when construction begins. For all other technologies, the expiration date is based on when the system is placed in service (fully installed and being used for its intended purpose).

Table 12 - Investment Tax Credits by Year and Technology

Technology	2016	2017	2018	2019	2020	2021	2022	Future Years
PV, Solar Water Heating, Solar Space Heating/Cooling, Solar Process Heat	30%	30%	30%	30%	26%	22%	10%	10%
Hybrid Solar Lighting, Fuel Cells, & Small Wind	30%	-	-	-	-	-	-	-
Geothermal Heat Pumps, Microtubines, Combined Heat and Power Systems	10%	-	-	-	-	-	-	-
Geothermal Electric	10%	10%	10%	10%	10%	10%	10%	10%
Large Wind	30%	24%	18%	12%	-	-	-	-

Solar Technologies

Eligible solar energy property includes equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat. Hybrid solar lighting systems, which use solar energy to illuminate the inside of a structure using fiber-optic distributed sunlight, are eligible. Passive solar systems and solar pool-heating systems are not eligible.

Fuel Cells

The credit is equal to 30% of expenditures, with no maximum credit. However, the credit for fuel cells is capped at $1,500 per 0.5 kilowatt (kW) of capacity. Eligible property includes fuel cells with a minimum capacity of 0.5 kW that have an electricity-only generation efficiency of 30% or higher.

Small Wind Turbines

The credit is equal to 30% of expenditures, with no maximum credit for small wind turbines placed in service after December 31, 2008. Eligible small wind property includes wind turbines up to 100 kW in capacity.

Geothermal Systems

The credit is equal to 10% of expenditures, with no maximum credit limit stated. Eligible geothermal energy property includes geothermal heat pumps and equipment used to produce, distribute or use energy derived from a geothermal deposit. For electricity produced by geothermal power, equipment qualifies only up to, but not including, the electric transmission stage.

Microturbines

The credit is equal to 10% of expenditures, with no maximum credit limit stated (explicitly). The credit for microturbines is capped at $200 per kW of capacity. Eligible property includes microturbines up to 2 MW in capacity that have an electricity-only generation efficiency of 26% or higher.

Combined Heat and Power ("CHP")

The credit is equal to 10% of expenditures, with no maximum limit stated. Eligible CHP property generally includes systems up to 50 MW in capacity that exceed 60% energy efficiency, subject to certain limitations and reductions for large systems. The efficiency requirement does not apply to CHP systems that use biomass for at least 90% of the system's energy source, but the credit may be reduced for less-efficient systems.

See http://energy.gov/savings/business-energy-investment-tax-credit-itc for more details.

Impacts of Declining Tax Credits and Technology Installed Costs

Chart 11 through Chart 13 shown below reflect the near-term capacity price declines on a $/kW basis from 2016 - 2022 associated with the reduction in the installed costs of solar technologies relative to the levelized cost realized on a $/MWh assuming different levels of investment tax credits by year. The solar ITC assumptions are based on the federal investment tax credit assumptions shown on page 66.

Chart 11 – Solar PV Fixed, Impacts of Declining Tax Credits and Technology Installed Costs

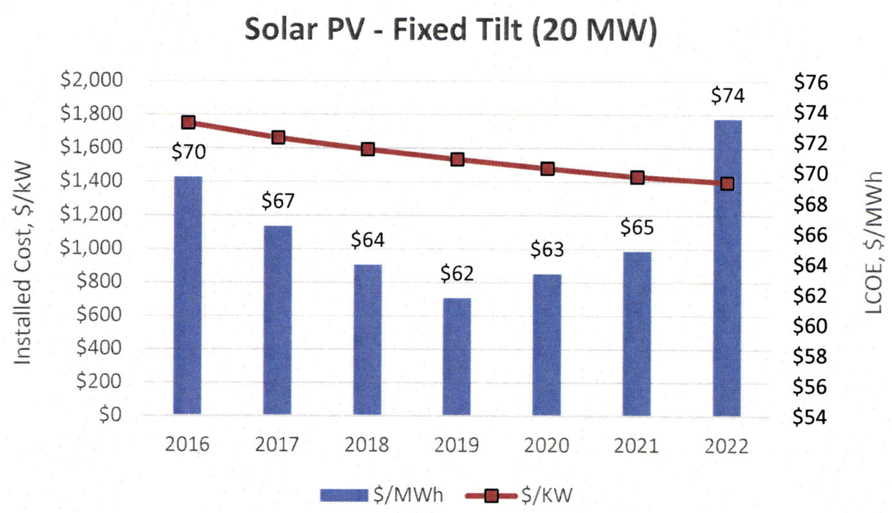


Chart 12 – Solar SAT, Impacts of Declining Tax Credits and Technology Installed Costs

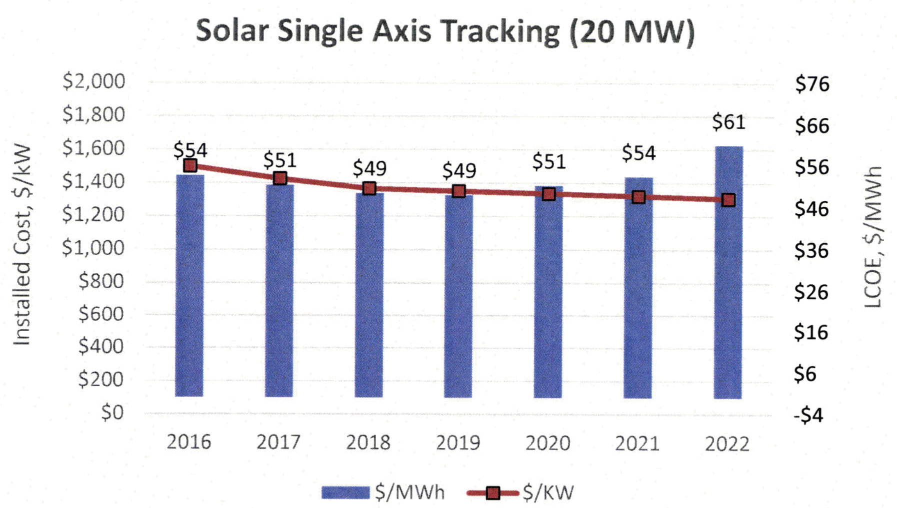
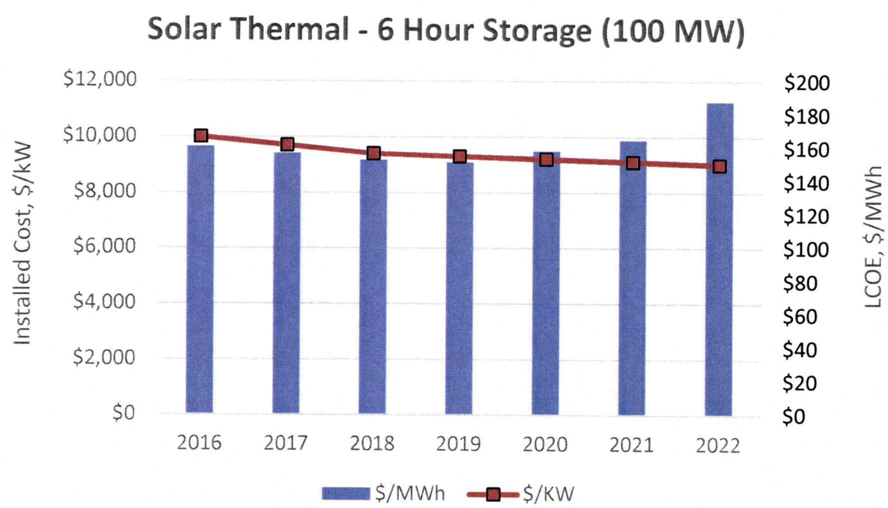


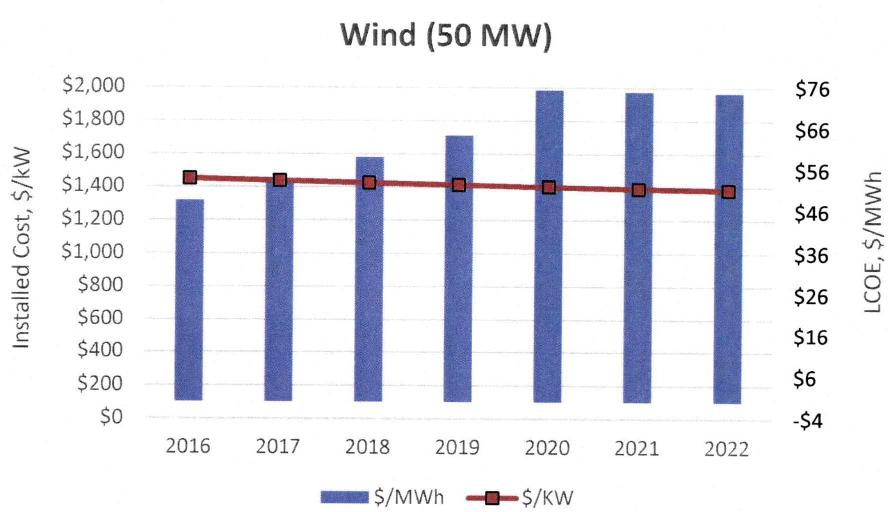
Chart 13 – Solar Thermal, Impacts of Declining Tax Credits and Technology Installed Costs



Impacts of Declining PTC and Technology Installed Costs

Chart 14 shown below reflects the near-term capacity price declines on a $/kW basis from 2016 - 2022 associated with the reduction in the installed costs of wind resources relative to the levelized cost realized on a $/MWh assuming different levels of production tax credits by year. The wind PTC assumptions are based on the federal production tax credit assumptions shown on 65.

Chart 14 – Wind, Impacts of Declining Production Tax Credits and Technology Price Installed Costs

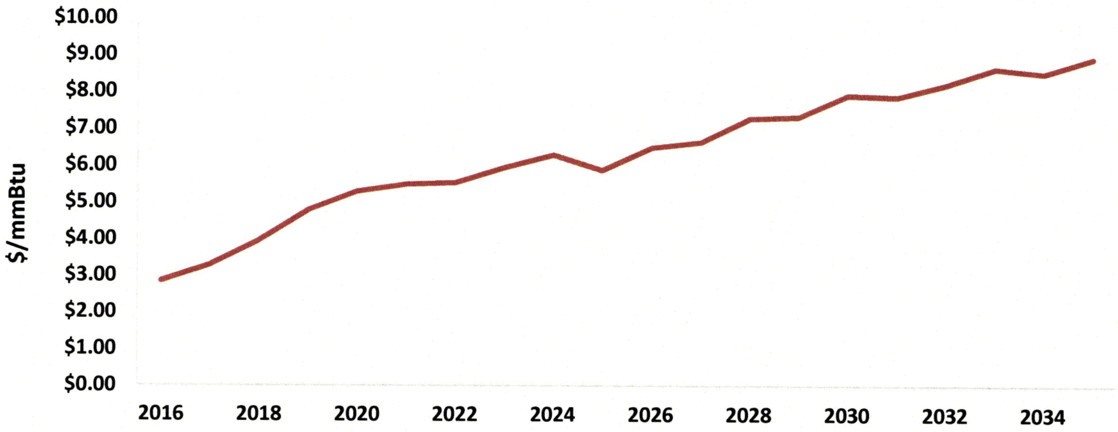


MARKET ASSUMPTIONS

Permian Natural Gas

UNSE's current forward price forecast for Permian natural gas starts at $2.86/MMBtu in 2016, and escalates to $8.93/MMBtu in 2035. Chart 15 - Permian Basin Natural Gas Prices shows the 20 year natural gas price projections in nominal dollars.

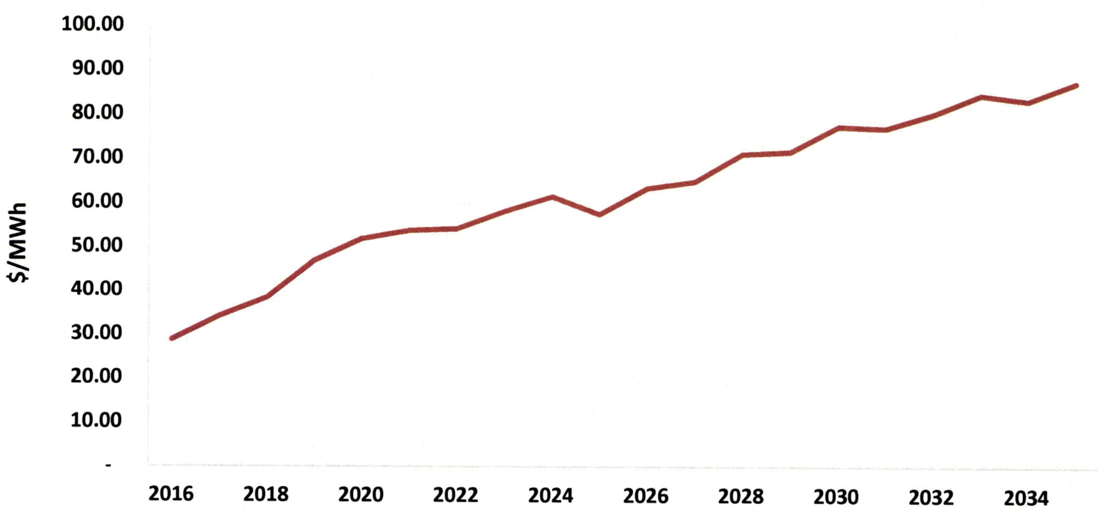
Chart 15 - Permian Basin Natural Gas Prices



Palo Verde (7x24) Market Prices

UNSE's current forward price forecast for 7x24 Palo Verde wholesale market prices starts at $28.76/MWh in 2016, and escalates to $87.35/MWh in 2035. Chart 16 - Palo Verde (7x24) Market Prices shows the 20 year wholesale power price projections in nominal dollars.

Chart 16 - Palo Verde (7x24) Market Prices



Chapter 7

2016 IRP SCENARIOS

The following section provides a description of the different scenarios to be analyzed in the 2017 Final IRP which is due on April 1, 2017. There are a total of 6 scenarios that will be presented in the IRP. The scenarios are listed and grouped as follows;

- Scenarios Requested by Decision No. 75068 (2014 IRP)
  - Energy Storage Case Plan
  - Small Nuclear Reactors Case Plan
  - Expanded Energy Efficiency Case Plan
  - Expanded Renewables Case Plan
- Additional Proposed Scenarios
  - Market Based Reference Case Plan
  - High Load Growth Case Plan

SCENARIOS REQUESTED IN DECISION NO. 75068 (2014 IRP)

Energy Storage Case Plan

In this case, UNSE will explore the potential of Energy Storage Systems (ESS) as a means for solving renewable generation intermittency and variability. The case will be designed to fully meet renewable and energy efficiency standards and to the extent that peaking capacity is required, ESS will be analyzed as a resource to cover peak demand requirements. The potential and applicability of ESS is described in Chapter 4 above.

Small Nuclear Reactors Case Plan

Small Nuclear Reactors (SMRs) is a technology that can be utilized to lower carbon dioxide (CO_2) emissions, as well as other pollutants, while providing reliable, sustained and efficient power output. In this case, UNSE will study the impact of SMRs as a resource to supplant retiring coal assets. The case will be designed to fully meet renewable and energy efficiency standards. This case will also be compliant with the Clean Power Plan.

Low Load Growth or Expanded Energy Efficiency Case Plan

For purposes of this scenario, it is assumed that UNSE realizes additional energy efficiency and distributed generation targets (above the EE standard). Under this scenario, UNSE's EE programs are expanded by program design and/or by technology efficiency improvements.

Expanded Renewables Case Plan

UNSE will present this scenario to study the impact of expanded renewable development. Under this scenario, UNSE will incrementally develop a community-scale renewable portfolio that ultimately results in UNSE serving 30% of its retail load by 2030 (with renewable resources). In this scenario, UNSE anticipates that complementary resources will be needed to maintain reliability and to achieve responsiveness to the intermittent and variable characteristics of solar and wind resources. A combination of different technologies (or individual technologies) will be tested to complement the renewables assumptions.

As higher percentages of renewable resources are added to UNSE's resource portfolio, UNSE anticipates the need for future investments in transmission, quick-start combustion turbines, energy storage devices and smart grid technologies in order to maintain reliable grid operations. For purposes of reliability, the 2017 Final IRP will study the expansion of battery storage technology, reciprocating internal combustion engines and other technology to support future ancillary service requirements for the grid.

Additional Proposed Scenarios

Market Based Reference Case Plan

For purposes of the 2017 Final IRP, UNSE will again develop the Market Based Reference Case plan. Under this scenario, it is assumed that UNSE relies on the wholesale market for limited amounts of firm wholesale purchased power agreements (PPA) to meet its future summer peaking requirements. This scenario provides some insights into how UNSE's resource portfolio might look if there is adequate supply of merchant resource capacity within the Desert Southwest region over the long-term. For purposes of this scenario, it is assumed that UNSE develops a portfolio of long and short-term purchased power agreements to cover its summer peaking requirements. It is assumed that UNSE limits its reliance on firm market capacity purchases to 200 MW per year. All other assumptions including transmission, CPP compliance, and renewable technology upgrades are the same as the Reference Case plan.

High Load Growth Case Plan

For purposes of the 2017 Final IRP, UNSE proposes to model a low load growth scenario that affect UNSE's long-term expansion plans. This third company scenario contemplates the increase of large industrial customer or a facility shut-down at an existing mining customer within UNSE's service territory.

Chapter 8

Fuel, Market and Demand Risk Analysis

For the 2017 Final IRP, UNSE plans to developed explicit market risk analytics for each candidate portfolio through the use of computer simulation analysis using AuroraXMP[15]. Specifically a stochastic based dispatch simulation will be used to develop a view on future trends related to natural gas prices, wholesale market prices, and retail demand. The results of this modeling will then be employed to quantify the risk uncertainty and evaluate the cost performance of each portfolio. This type of analysis ensures that the selected portfolio not only has the lowest expected cost, but is also robust enough to perform well against a wide range of possible load and market conditions.

As part of the Company's 2017 resource plan, UNSE plans to conduct risk analysis around the following key variables:

- Natural Gas Prices
- Wholesale Market Prices
- Retail Load and Demand

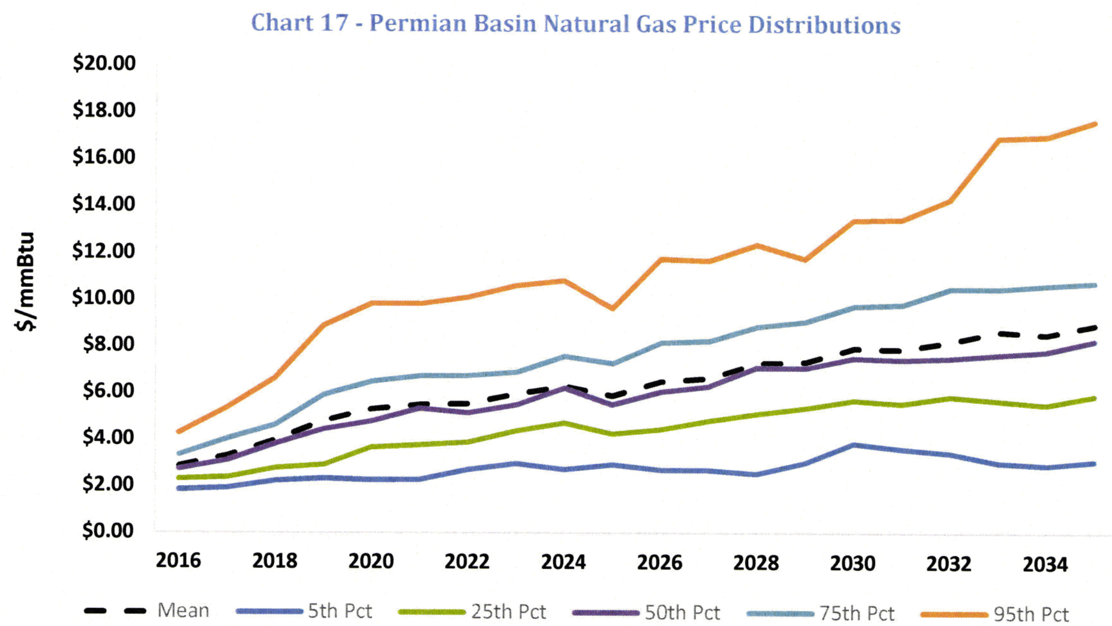
A summary of the input distributions are shown for all these variables on Chart 17 through Chart 19 below:

[15] AURORAxmp is a stochastic based dispatch simulation model used for resource planning production cost modeling. Additional information about AURORAxmp can be found at http://epis.com/

NATURAL GAS & WHOLESALE MARKET PRICE SENSITIVITY

Permian Natural Gas

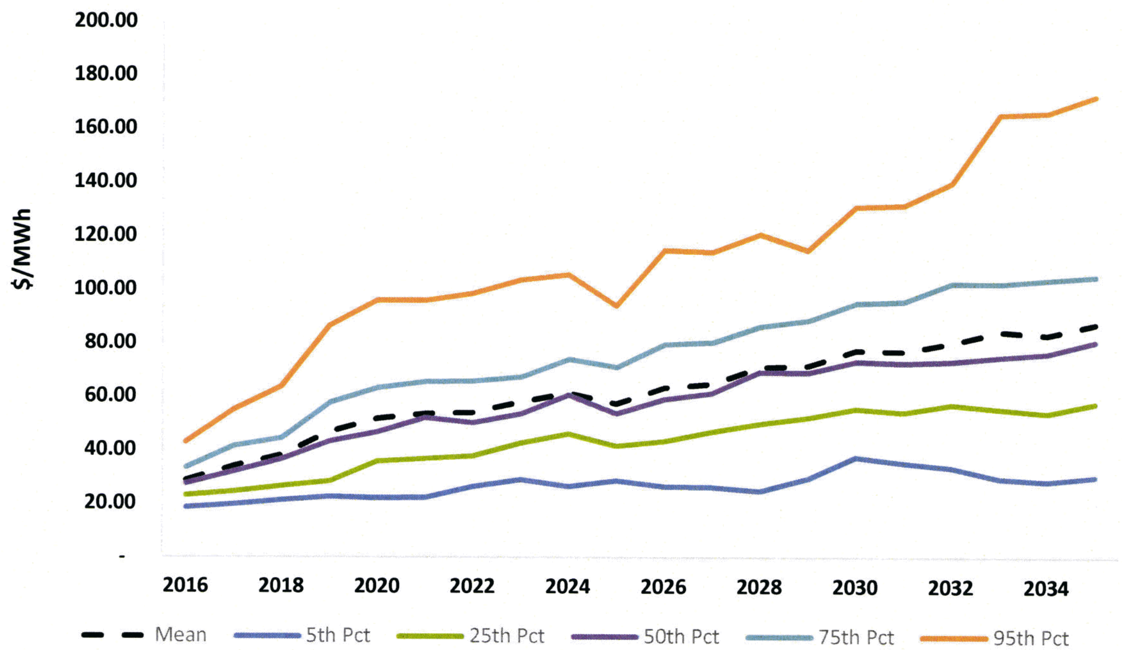
Chart 17 shows both the expected forward market prices as well as the expected price distributions for natural gas sourced from the Permian Basin.



Palo Verde (7x24) Market Prices

Chart 18 shows both the expected forward wholesale market prices as well as the expected price distributions for power sourced from the Palo Verde market.

Chart 18 - Palo Verde (7x24) Market Price Distributions

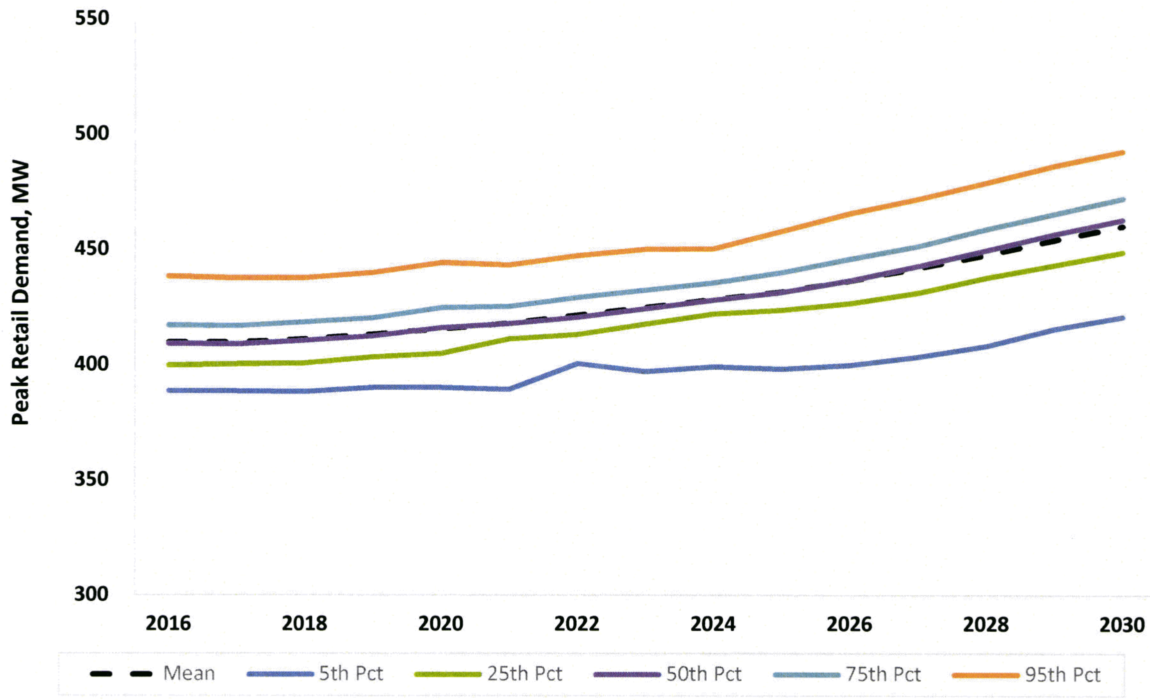


When considering Chart 17 and Chart 18 from above, it is important to note that the summary statistics are aggregations rather than individual price paths. For instance the P95 number for a given year represents the point which 95% of simulated values fall below. Individual price paths mimic realistic behavior by being subject to the price "spikes," mean reversion, and uneven trend observed in actual markets.

LOAD GROWTH SENSITIVITY

Chart 19 shows both the expected retail peak demand as well as the expected demand distributions for UNSE's retail customers.

Chart 19 – UNSE Peak Retail Demand Distributions



Chapter 9

2016 – 2017 Action Plan

In accordance with Decision No. 75269, this 2016 Preliminary IRP introduces and discusses the issues that UNSE may analyze in detail for the final IRP. UNSE will continue to develop a final IRP in accordance with the schedule outlined in Decision No. 75269. The schedule includes the following milestones, which UNSE will meet.

File 2016 Preliminary Integrated Resource Plan	March 1, 2016
Submit Preliminary Integrated Resource Plan Update	October 1, 2016
Pre-filing Workshop on Final Integrated Resource Plan	November 2016
File 2017 Final Integrated Resource Plan	April 3, 2017

The decision to defer the deadline for filing a Final IRP was largely due to the impact that the CPP is anticipated to have on resource plans, and the high degree of uncertainly around how the CPP will be implemented in the jurisdictions where the regulated LSEs have facilities. As described previously, the US Supreme Court has issued a stay of the CPP pending litigation in the DC Circuit Court and including potential US Supreme Court review. During the stay, States are not obligated to continue to work on State Plans, and the deadlines for those plans, as well as compliance timelines for affected units, will need to be adjusted if the rule remains in place following litigation. Arizona and New Mexico are currently evaluating if and how to proceed in light of the stay. A final ruling on the CPP litigation is not expected prior to June of 2017, and may not be issued until 2018.

The 2017 Final IRP will be due prior to the completion of all of the State Plans governing CPP implementation, therefore, UNSE anticipates that the Final IRP will have to accommodate some level of uncertainty with regard to CPP implementation. Scenarios and/or sensitivities to address this uncertainty will be presented in the October 2016 IRP Update, to the extent they have been identified. Additional scenarios and/or sensitivities may become necessary prior to completion of the 2017 Final IRP. UNSE will continue to actively participate in the development of these State Plans, in an attempt to gather as much clarity concerning CPP implementation as possible.

UNSE has developed a short-term action plan based on the resource decisions that must be implemented in parallel with development of the 2017 Final IRP. Under this action plan, additional detailed study work will be conducted to validate all technical and financial assumptions prior to any final implementation decisions.

UNSE's action plan includes the following:

- UNSE plans to continue with its community scale build out of its current renewable energy standard implementation plans. UNSE anticipates that an additional 35 MW of new renewable capacity will be in-service by the end of 2016 raising the total distributed generation and utility scale capacity on UNSE's system to approximately 83 MW. By the end of 2016, renewable resources will make up close to 26% of UNSE's total nameplate generation capacity. As a result, UNSE is currently investing its time and resources into a number of research and development activities that will determine the future need for storage and smart grid technologies to support the grid. UNSE will learn from the experiences of TEP in its development of two 10 MW energy storage projects slated for in service in early 2017 (pending ACC approval).

- UNSE will continue to implement cost-effective EE programs based on the Arizona EE Standard. UNSE will closely monitor its energy efficiency program implementations and adjust its near-term capacity plans accordingly.

- As part of its near-term portfolio strategy, UNSE will continue to utilize the wholesale merchant market for the acquisition of short-term market based capacity products. In addition, UNSE will continue to monitor the wholesale market for other resource alternatives such long-term purchased power agreements and low cost plant acquisitions. UNSE will also monitor its natural gas hedging requirements as it reduces its reliance on coal based generation in favor of natural gas resources and make recommendations on potential fuel hedging changes if they become necessary.

UNSE plans to communicate any major change in its anticipated resource plan with the Arizona Corporation Commission as part of its ongoing planning activities. UNSE hopes this dialog will allow the Commission an opportunity to help shape UNSE's future resource portfolio outcomes while providing UNSE with greater regulatory certainty with regards to future resource investment decisions.